February 24, 2012

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool, Market Rule 1 Revisions Relating to Coordinated Transaction Scheduling; Docket No. ER12-___-000**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO" or "ISO-NE") and the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties") hereby jointly submit this transmittal letter and revised Tariff sections (the "CTS Tariff Revisions") to implement Coordinated Transaction Scheduling between New England and New York over certain AC interfaces ("Coordinated Transaction Scheduling").[3] Coordinated Transaction Scheduling was developed as a joint effort between ISO-NE and the New York Independent System Operator, Inc. ("NYISO") to enhance the market efficiency of external transactions (*i.e.*, energy imports and exports) between the two regions. A study completed by the two regions' external market monitor indicates that implementing Coordinated Transaction Scheduling has the potential to produce significant reductions in

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

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

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

production costs and energy expenditures.[4] The ISO also submits herewith the supporting testimony of Matthew White and Janine Dombrowski (the "White-Dombrowski Testimony"), sponsored solely by the ISO.[5]

This transmittal letter explains the identified inefficiencies with the current external transaction scheduling process, the root causes of these inefficiencies, and the way in which Coordinated Transaction Scheduling addresses each of the identified inefficiencies and their root causes. The transmittal letter also explains each of the Tariff revisions proposed to implement Coordinated Transaction Scheduling. Finally, it describes Tariff revisions to implement a process agreed to by both ISO-NE and the NYISO to evaluate Coordinated Transaction Scheduling at the two and three year points following its implementation and, if warranted, either make refinements to the scheduling process or replace it with an alternative scheduling process, known as "Tie Optimization." On December 28, 2011, the NYISO filed parallel tariff revisions to implement Coordinated Transaction Scheduling in New York.[6] If the proposed revisions to the ISO-NE and NYISO are accepted by the Commission, the ISOs will work together to implement Coordinated Transaction Scheduling under the timeline explained herein.

I. REQUESTED EFFECTIVE DATES; COMMISSION ORDER; PLANNED IMPLEMENTATION OF COORDINATED TRANSACTION SCHEDULING.

The Filing Parties are requesting that the Commission accept the revisions herein as filed, without suspension or hearing, to be effective on or after August 1, 2013, with two weeks' prior notice to be provided by the ISO for the actual effective date. Pursuant to Section 35.3(a), all rate schedules or any part thereof must be filed with the Commission and posted not "more than one hundred-twenty days prior to the date on which the electric service is to commence and become effective." The Filing Parties request waiver of the provisions of Section 35.3(a)(1) of the Commission's rules and regulations to permit this requested effective date and believe that good cause exists to permit this waiver. To implement Coordinated Transaction Scheduling will require development of a joint scheduling system between ISO-NE and NYISO and significant modifications to ISO-NE's existing External Transaction scheduling software and business procedures. The requested effective date affords the two ISOs the time necessary to complete this implementation.

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[4] *See* David B. Patton, PhD, Potomac Economics, *Benefits of Coordinating the Interchange Between New York and New England*, January 21, 2011, included as an attachment to this filing.

[5] Dr. White is the ISO's Senior Economist. Dr. Dombrowski is a Principal Market Design Analyst with the ISO.

[6] New York Independent System Operator, Inc., Proposed Tariff Amendments to Add External Coordinated Transaction Scheduling Market Rules and Request for Waiver Docket No. ER12-ER12-701-000 (filed December 28, 2011) (the "NYISO CTS Filing"), Transmittal Letter at fn 25.

Given the changes sought herein, a Commission order in the normal course of business (*i.e.*, prior to the 60th day following the date of this filing) is respectfully requested. This will provide the ISO with certainty before undertaking the significant time and financial investment to implement Coordinated Transaction Scheduling.

At this time the ISO is working with the NYISO to implement Coordinated Transaction Scheduling at the New York Northern AC external Location and the Northport-Norwalk external Location. The Tariff revisions in Section III.1.10.7.A of Market Rule 1 reflect this intended implementation. As the NYISO indicates in its filing materials for Coordinated Transaction Scheduling, at this time only the New York Northern AC external Location has been evaluated for Coordinated Transaction Scheduling implementation.[7] In the event further evaluation reveals that implementation for the Northport-Norwalk external Location is not feasible, the ISO will file a Tariff amendment to remove reference to this latter location before Coordinated Transaction Scheduling becomes effective.

II. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS.

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

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 430 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[8] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from

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[7] NYISO CTS Filing, transmittal letter at fn 25.

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

state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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III. STANDARD OF REVIEW.

These changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[10] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[11] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just

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

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

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

and reasonable.'"[12] 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."[13] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[14] 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.[15]

IV. BACKGROUND.

A. The Current External Transaction Scheduling Process.

Under the current inter-regional trading system, market participants in New England and New York submit separate external transaction requests to each ISO. For instance, an offer to buy, or export, from New England is submitted only to ISO-NE, and the matching offer to sell, or import, into New York is submitted only to the NYISO. There is no economic coordination between the ISOs when they evaluate these offers and use them to determine the net interface schedule.

In New England, a real-time External Transaction request must be submitted by a participant to the ISO no later than 60 minutes prior to the hour for which the participant requests that delivery commence;[16] the ISO determines whether or not to accept a "real-time" External Transaction about forty-five minutes before the delivery hour; and the scheduled transaction quantity remains fixed for the full delivery hour. The combined effect of the one hour minimum duration of an external transaction and the one hour advance offer submittal requirement – the processing time required by ISOs to exchange information about independently submitted external transaction requests and the resulting upcoming physical power flow changes between areas – means that imports or exports into or out of New England must be submitted up to a full two hours before their delivery is to be completed.

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[12] *Id.* at 9.

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

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

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

[16] Under Tariff § III.1.10.7(a), all priced External Transactions in the Real-Time Energy Market must be submitted by noon of the day before the Operting Day. Under § III.1.10.9(c), Self-Scheduled External Transactions must be submitted at least one hour before the delivery period.

B. Inefficiencies of the Current External Transaction Scheduling Process, Their Root Causes, and Estimated Cost Savings of Coordinated Transaction Scheduling.

1. Identified Inefficiences with Current Scheduling Process.

The ISO's External Market Monitor, in conjunction with the ISO, has identified inefficiencies with the current external transaction scheduling process, in particular with the way in which power is imported and exported between New England and New York.[17] First, as Drs. White and Dombrowski address in their testimony,[18] transmission operational data indicate that there is significant under-utilized transmission capacity between New York and New England. This under-utilization is taking place during times when there is sufficient transmission capacity to move additional power from the region with the lower Locational Marginal Price ("LMP") to the region with the higher LMP. That means the combined cost of operating the power systems in the two regions would be lower if the existing transmission capacity between them was used to further displace higher-cost generation in one region with lower-cost generation in the other region.

The second inefficiency, also addressed by Drs. White and Dombrowski in their testimony,[19] is that current scheduling procedures often result in net interchange schedules from the *higher* price region to the *lower* price region. This phenomenon is known as *counter-intuitive flow*, because participants' economic interests would be expected to produce interchange schedules in the opposite direction, from the lower-price to the higher-price region. Counter-intuitive flow means that the interchange schedule is causing the exporting region to increase production from high-cost generation at the margin, and the importing region to decrease production from low-cost generation at the margin, thereby raising the total costs of serving demand, relative to a level of flows that equalized the marginal cost of generation in each region.

2. Root Causes of Inefficiencies.

The ISOs established that there are three root causes of the identified inefficiencies in the scheduling of the interfaces:[20]

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[17] These inefficiencies, and their adverse impact on the combined cost of operating the power systems in the two regions, are documented in detail in Sections II.A and II.B of the joint *ISO New England Inc. and New York Independent System Operator, Inc. White Paper* on *Inter-Regional Interchange Scheduling: Analysis and Options* (January 5, 2011) (the "Joint ISO White Paper"), which is included as an attachment to this filing. Dr. White was a principal author of the Joint ISO White Paper.

[18] White-Dombrowski Testimony at p. 4.

[19] *Id.*

[20] These causes are explained in greater detail in the White-Dombrowski Testimony at pp. 8-18.

- Latency Delay;
- Non-Economic Clearing; and
- Cross-Border Transaction Costs.

Each of these causes is discussed below.

a. Latency Delay[21]

During the nearly two-hour time delay between when external transactions are scheduled and when their delivery is completed, system conditions and LMPs may change in each region. This *latency delay* can have three adverse consequences:

- *Transmission under-utilization.* If the importing region's LMP rises relative to the exporting region's LMP after all external transactions are scheduled, imports are more valuable in real-time than the market anticipated when interchange schedules were set an hour earlier. While power is flowing in the direction to lower the two regions' combined total production costs, *not enough* power is flowing the right direction to minimize total production costs.

- *Counter-intuitive flow.* If the importing region's LMP falls relative to the exporting region's LMP after external transactions are scheduled, counter-intuitive flows may result. That inefficiently displaces low-cost generation at the margin in one region with high-cost generation at the margin in the other region, *increasing* total costs for the two regions relative to the efficient level of interchange.

- *Unnecessary economic risk.* If the price difference between regions changes after a participant's external transaction is scheduled, the market participant can end up "buying high and selling low," losing money on each megawatt scheduled. This risk poses a deterrent to submitting external transactions in the first place, exacerbating the transmission under-utilization problem.

b. Non-Economic Clearing[22]

The ISOs make decisions about which import and export schedule requests to accept without economic coordination. As explained above, market participants submit separate external transaction requests to each ISO. There is no economic coordination between the ISOs when they evaluate these offers and use them to determine the net interchange schedule. This absence of economic coordination when external transaction

[21] White-Dombrowski Testimony at pp. 9-11.

[22] *Id.* at pp. 11-14.

requests are accepted produces inefficient interchange schedules, and raises total system costs.

Data studied by the two ISOs indicate that non-economic clearing is fairly prevalent. Data for all hours from July through December 2009 indicate that the ISOs are scheduling power from the high-to-low cost region, raising expected total production costs (at the margin), 44 percent of the time.[23] This is not because of latency; these data are based on the ISOs' expected LMPs in each region as of the time the ISOs set the net interchange schedule, which occurs approximately 45 minutes in advance. The data further indicate that even when the net interchange schedule is in the economically correct direction (at the margin), too little power is being scheduled to converge the LMPs most of these hours. That means total system costs for the ISOs are unnecessarily high: In these hours, trade fails to displace high-cost generation with additional lower-cost generation available from the exporting region.

c. Cross-Border Transaction Costs[24]

Both New England and New York impose a number of different fees and charges on external transactions. For example, In New England a portion of total Net Commitment Period Compensation ("NCPC") costs (uplift) is allocated to real-time External Transactions. These charges can be highly variable from day to day, are difficult to predict in advance, and there is no practical means for a market participant to hedge against them.

The allocation of these costs and other ISO fees to external transactions serves as an economic impediment to trade between regions.[25] Market Participants will likely factor these fees into their external transaction bids, in order to cover the expected fees and charges levied by the ISOs. This behavior prevents price convergence between regions, even if the first and second root causes are eliminated; the absence of price convergence adversely impacts the two regions' combined total production costs. System costs will be higher than necessary because the existing transmission capacity between regions will tend to be under-utilized, relative to external transaction volumes if there were no transaction fees and charges on inter-regional trade.

These causes are explained in more detail in the White-Dombrowski Testimony and in Section II.C of the Joint ISO White Paper.

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[23] *Id.* at p. 13.

[24] *Id.* at pp. 14-18.

[25] *Id.* at pp. 16-18.

3. Estimated Economic Benefits of Coordinated Transaction Scheduling.

An analysis performed by Potomac Economics, New England's External Market Monitor, at the request of ISO-NE and the NYISO estimated the impact that the Coordinated Transaction Scheduling system would have had on the two regions' combined total production costs, had it been in place during the years 2008, 2009 and 2010. The analysis also examined the changes in average LMPs in each region, and changes in load's energy market expenditures, relative to the status quo.[26]

The External Market Monitor's analysis indicates that the estimated cumulative reduction in total production costs over the three-year study period resulting from more efficient interface scheduling under Coordinated Transaction Schedule would be between $26 to $34 million for the two regions combined.[27] The estimated cumulative reduction in total energy expenditures by load over the three-year study period under Coordinated Transaction Scheduling ranges from $387 million to $417 million.[28] Of this total reduction, the share accruing to load in New England ranges from $183 million to $219 million.[29]

C. Proposed Alternatives to Address The Identified Inefficiencies.

In response to the External Market Monitor's evaluation, the ISO, working jointly with the NYISO and the External Market Monitor, developed two market design proposals to improve the efficiency of external transaction scheduling between New England and New York. The alternative proposal to Coordinated Transaction Scheduling, which is referred to as Tie Optimization, has several features in common

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[26] The External Market Monitor presented its findings to New England stakeholders on January 21, 2011. A copy of its presentation is included with this filing. The External Market Monitor's analysis is also addressed in the White-Dombrowski Testimony at pp. 5-8.

[27] The range of values reflects estimated results under a range of assumptions about the performance of the new scheduling system. The annual figures vary modestly from year to year, being higher when fuel prices are high, as occurred in 2008, and lower when fuel costs decline, as occurred in 2009.

[28] The range results from the study's evaluation of different assumptions regarding the performance of the new scheduling system.

[29] The External Market Monitor's analysis also found that both regions' LMPs would be lower on an annual average basis. *See* the White-Dombrowski Testimony at p. 7 ("…within each region the decrease in LMP when more efficient scheduling increases imports exceeds (in magnitude) the increase in LMP when more efficient scheduling increases exports, on an average annual basis (*cf.*, Potomac Economics Study, p. 10). Thus each region's average LMP falls overall. This explains the External Market Monitor's finding that total annual energy expenditures by load would be lower in both New York and New England, in each year studied, with more efficient interchange scheduling under Coordinated Transaction Scheduling.").

with the proposal filed herewith, but treats external transaction clearing in a manner that is similar to the clearing of offers and bids at internal interfaces.[30]

Following a series of meetings between New England and New York stakeholders during 2011 to evaluate the External Market Monitor's analysis and discuss the two alternative proposals, stakeholders in New York voted to support Coordinated Transaction Scheduling,[31] and stakeholders in New England voted to support Tie Optimization.[32] To bring the regions' market participants together on a going-forward strategy, the ISOs developed the procedure memorialized in Section III.1.10.7.B of Market Rule 1.[33] This procedure provides for a series of future reviews and analyses whereby market rules to replace CTS could be pursued. Section III.1.10.7.B is addressed in more detail in Section VII of this transmittal letter.

V. RATIONALE FOR COORDINATED TRANSACTION SCHEDULING.

Coordinated Transaction Scheduling will address each of the identified inefficiencies and their root causes. To minimize latency delay, it uses more frequent interface scheduling to reduce latency delay. To reduce non-economic clearing, it uses a simplified bid format and a clearing rule that coordinates economic clearing of external transactions between the two ISOs. To reduce cross-border transaction costs, it eliminates the transaction fees from external transactions at interfaces subject to Coordinated Transaction Scheduling.[34]

A. Minimizing Latency Delay.

To minimize latency delays, under Coordinated Transaction Scheduling the ISOs will update – every 15 minutes – the interface schedule across each AC interface between New England and New York for which Coordinated Transaction Scheduling is implemented.[35] The interface schedule is fixed for 15 minutes between each update.

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[30] Tie Optimization is described in Section III of the Joint ISO White Paper.

[31] *See* Minutes of the June 1, 2011 NYISO Business Issues Committee meeting, available at http://www.nyiso.com/public/webdocs/committees/bic/meeting_materials/2011-06-01/Final_BIC_Minutes_060111.pdf.

[32] *See* Minutes of the June 10, 2011 NEPOOL Participants Committee meeting, *available at* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mins/2011/npc_2011_0610.pdf.

[33] The analogous provision is addressed in the NYISO CTS Filing in the transmittal letter at pp. 15-17.

[34] The following explanation of the manner in which Coordinated Transaction Scheduling addresses the identified inefficiencies is based upon the White-Dombrowski Testimony at pp. 18-22.

[35] White-Dombrowski Testimony at pp. 18-19.

Within each 15-minute interval, each ISO will perform its internal dispatch as it does today.

The choice of 15-minute intervals is determined by current technology and operational considerations. With additional advances in technology, it may be possible to further shorten this interval. The key technological and operational constraint is that interface scheduling requires “pre-scheduling” runs of the unit dispatch system to be performed by the ISOs, and an exchange of economic solution and external transaction information between ISOs after these pre-scheduling runs. The resulting coordinated interface schedule is then incorporated into each ISO’s internal dispatch solutions during the 15-minute interval to which the interchange schedule applies.[36]

B. Coordinated Bidding and Clearing to Improve Economic Efficiency.

Under the current system, there is no economic coordination between the ISOs when the net interchange schedule is determined. This produces inefficient interchange schedules, and raises total system costs. Under Coordinated Transaction Scheduling, a participant may submit a single real-time external transaction bid that is used by both ISOs. The two ISOs apply a coordinated clearing process that determines the net interchange schedule.[37]

Specifically, under Coordinated Transaction Scheduling, a real-time external transaction is accepted if the offered price is less than (or equal to) the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled.[38] This is an economically-coordinated clearing process that will tend to set the net interchange to flow from the region with lower prices to the region with higher prices. Doing so improves economic efficiency by displacing higher-cost generation in one region with lower-cost generation in the other, which lowers the combined costs of operating the two regions’ power systems.

C. Elimination of Charges, Fees and Credits for External Transactions.

For external transactions at interfaces subject to Coordinated Transaction Scheduling, the ISO will no longer apply certain fees, charges, and associated credits.[39] These include fees, charges, and credits associated with the costs of uplift (*i.e.*, NCPC),[40] emergency energy purchases and sales,[41] purchases and sales to maintain minimum

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[36] *Id.* at p. 19.

[37] *Id.*

[38] CTS Tariff Revisions at § III.1.10.7.A(c). *See* White-Dombrowski Testimony at p. 20.

[39] *See* White-Dombrowski Testimony at pp. 20-21.

[40] CTS Tariff Revisions at § III.3.2.3 and § III, Appendix F.

[41] CTS Tariff Revisions at § III.3.2.6.

flow,[42] costs for regulation service,[43] and credits and charges for the difference between the actual and scheduled energy flows.[44] The aggregated amounts of the fees, charges and credits currently allocated to these External Tansactions will be reallocated to Market Participants' other transactions that are presently allocated these amounts.

VI. EXPLANATION AND JUSTIFICATION OF TARIFF REVISIONS.

As explained above, Coordinated Transaction Scheduling uses a simplified bid format, called an "Interface Bid," and coordinated economic clearing of real-time external transactions by the ISO and the NYISO. Coordinated Transaction Scheduling also employs higher frequency scheduling of the external interface between New England and New York, and eliminates certain charges and credits on external transactions that deter trade.[45] To implement Coordinated Transaction Scheduling, Market Rule 1 is being modified as follows:

- A new Market Rule 1 section is being created to address the offer requirements for External Transactions subject to Coordinated Transaction Scheduling, as well as the clearing mechanism for such transactions;[46]

- The settlement rules in Section III.3 of Market Rule 1 are being modified to account for the 15-minute settlement of External Transactions subject to Coordinated Transaction Scheduling;[47]

- The provisions of Market Rule 1 pertaining to congestion are being modified to expressly account for the pricing of congestion at interfaces for which Coordinated Transaction Scheduling is being implemented;[48] and

- Provisions addressing fee, charge and credit eligibility are being modified to exempt External Transactions subject to Coordinated Transaction Scheduling.[49]

In addition, at this time the ISO is proposing conforming changes to the Forward Capacity Market rules, in order to address how certain features of Coordinated Transaction Scheduling impact the rights and obligations of Import Capacity Resources.

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[42] CTS Tariff Revisions at § III.3.2.6A and § III.3.2.1(b)(v)..

[43] CTS Tariff Revisions at § III.3.2.2.

[44] CTS Tariff Revisions at § III.3.2.1(l)..

[45] *Id.* at p. 22.

[46] *See* CTS Tariff Revisions at § III.1.10.7.A and § III.2.5(a).

[47] *See generally* CTS Tariff Revisions at § III.3.

[48] CTS Tariff Revisions at § III.2.6(a).

[49] See citations above in nn. 40-44.

A. Coordinated Transaction Scheduling Offer Requirements.

Coordinated Transaction Scheduling is being implemented through a new form of external transaction, referred to as a Coordinated External Transaction, and its counterpart in the Real-Time Energy Market, an Interface Bid. Coordinated External Transactions are subject to a number of the same Day-Ahead Energy Market offer requirements as all other forms of External Transactions,[50] but the rules for Interface Bids in the Real-Time Energy Market are markedly different.

1. Coordinated External Transactions.

A Coordinated External Transaction is "an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented."[51] External Transactions generally are subject to the offer and scheduling provisions in Section III.1.10 of Market Rule 1. Section III.1.10.7 addresses a number of offer requirements that are particular to External Transactions.[52] Coordinated External Transactions are subject to many of the same offer and scheduling requirements in Section III.1.10, but are expressly exempt from the requirements in Section III.1.10.7. Instead, a new Section III.1.10.7.A is being added to address offer requirements for Coordinated External Transactions.

Section III.1.10.7.A specifies that a Coordinated External Transaction submitted in the Day-Ahead Energy Market must be followed by an Interface Bid submitted in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Section III.1.10.7.A also states the required parameters for an Interface Bid, *i.e.*,

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[50] Under the current tariff, an External Transaction is **"**the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market." Tariff, at § I.2.2.

[51] CTS Tariff Revisions at § I.2.2. A transaction to wheel energy into, out of or through the New England Control Area is expressly excluded from the definition of a Coordinated External Transaction. Wheeling transactions will continue to be scheduled on an hourly basis until further evaluation is performed on whether the third control area (other than New York and New England) where a wheeling transaction sources or sinks is able to schedule external transactions on a 15-minute basis.

[52] Section III.1.10.7 addresses Real-Time Energy Market offer requirements, offer block and time interval submittal requirements, scheduling of External Transactions in the event an emergency is anticipated, NERC E-Tag and related offer requirements when an external interface requires advance transmission reservations, priority treatment for External Transactions that meet certain specified offer requirements (and associated treatment of those transactions when an underlying resource is committed for local second contingency protection), and treatment of External Transactions when a system-wide capacity deficiency occurs or is forecasted.

that it must specify a duration of one or more consecutive 15-minute increments, that it must include a price (positive or negative), quantity and direction for each 15 minute increment, and that it must be submitted no later than 75 minutes before the start of the period for which it is being offered. In addition, Section III.1.10.7.A specifies that all Coordinated External Transactions in the Day-Ahead or Real-Time markets must be submitted with the associated NERC E-Tag. The E-Tag requirement enables the ISO and the NYISO to coordinate expected interchange schedules after the close of each ISO's Day-Ahead market and prior to commencement of the operating day.

2. Interface Bids.

An Interface Bid is "a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented."[53] This unified bid structure is designed to resolve one of the three root causes of the existing system's inefficiencies, the non-economic clearing problem, which was described above in Section IV.B.2.[54]

Mechanically, an Interface Bid consists of four components: A price, a direction, a quantity, and the time period to which the bid applies.[55] The price indicates the minimum expected price difference between the two regions that the participant is willing to accept. The direction indicates in which region the participant wants to buy, and in which it wants to sell. The quantity indicates how many megawatts the participant is willing to transact. The time period specifies which one, or more, 15-minute scheduling interval(s) to which the bid applies.[56]

To improve bid submission and processing procedures for participants, Interface Bids will be submitted simultaneously in New York and New England using a common bid submission platform. The platform is intended to provide a one-stop, automated bid submission and validation tool for Interface Bids under Coordinating Transaction Scheduling. The information submitted by a market participant to this common platform will be accessible to, and used by, both ISOs to coordinate clearing of the real-time external transaction bids that determine the net interface schedule.[57]

The common submission platform is expected to eliminate 'failure to check-out' outcomes that occur when the real-time external transaction data a market participant submits independently to each ISO do not match each other exactly. Such problems are

[53] CTS Tariff Revisions at § I.2.2.

[54] White-Dombrowski Testimony. at p. 23.

[55] CTS Tariff Revisions at § III.1.10.7.A(b).

[56] White-Dombrowski Testimony at pp. 23-24.

[57] *Id.* at p. 24.

an inefficient source of risk for market participants submitting external transaction requests today.[58]

Current rules require that External Transactions be submitted into the Real-Time Energy Market no later than 75 minutes before the delivery hour on the New York side, and no later than 60 minutes before the delivery hour on the New England side. These submission deadlines need to become a common point in time, since market participants will now submit a single bid. Under the new Section III.1.10.7.A, Interface Bids must be submitted no later than 75 minutes in advance of the start of the delivery period to which the interface bid applies.[59] This is to accommodate the look-ahead information needs of the ISOs' dispatch and commitment systems, which on the New York side assess changes in physical interface schedules 75 minutes ahead of time.[60]

B. Coordinated Transaction Scheduling Clearing.

1. Clearing – Day-Ahead Energy Market.

In the Day-Ahead Energy Market, Coordinated External Transactions will be cleared using the same process that applies for all other internal offers and bids and External Transactions, *i.e.*, a determination based on "the least-cost, security-constrained unit commitment and dispatch."[61] This calculation is performed on an hourly basis using "a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist."[62]

Section 2.6(a), which explains the clearing mechanism for the Day-Ahead Energy Market as well as the calculation of Day-Ahead Prices, has been revised to clarify that the current constraint utilized to prevent congestion from being factored into the determination of Day-Ahead Prices will not apply for Coordinated External Transactions. This revision is addressed in more detail below in Section VI.D on congestion pricing.

2. Clearing – Real-Time Energy Market.

As with external transactions between the two regions under the current system, under Coordinated Transaction Scheduling the ISOs will use participants' real-time external transaction bids and the as-bid costs of generators and other physical supply

[58] *Id.*

[59] CTS Tariff Revisions at § III.1.10.7.A(b).

[60] White-Dombrowski Testimony at p. 25.

[61] Market Rule 1, § III.2.6(a).

[62] Market Rule 1, § III.2.6(a).

resources in each region to determine the real-time net interchange schedule.[63] However, the process by which this information is used to clear a real-time external transaction request differs between Coordinated Transaction Scheduling and the existing inter-regional system.

Under today's external transaction scheduling mechanisms, Market Participants submit separate external transaction requests to each ISO (*e.g.*, an offer to buy, or export, from ISO-NE is submitted only to ISO-NE, and the matching offer to sell, or import, in NYISO is submitted only to NYISO). There is no economic coordination between the ISOs when they set the net interchange schedule. In contrast, under Coordinated Transaction Scheduling, the two ISOs apply a coordinated process that determines the net interchange schedule. Specifically, an Interface Bid will clear if the offered price is less than the expected LMP difference across the external interface in the requested direction, as of the time the interface is scheduled.[64]

As noted earlier, the current inter-regional trading system uses an hourly external transaction scheduling system. To reduce latency delay under Coordinated Transaction Scheduling, Interface Bids will be cleared every 15 minutes. The net interchange schedule will be updated at the same frequency. The total aggregate quantity of cleared Interface Bids for a particular 15-minute time interval shall determine the net interface schedule for that time interval.[65]

The purpose of this economic coordination is to resolve the "non-economic clearing" root cause of inefficient interchange schedules, described previously.[66] By performing a coordinated evaluation of whether each Interface Bid is expected to be "economic," the quantity (in megawatts) of all external transaction requests that clear for an upcoming 15-minute interval will produce a net interface schedule that tends to converge prices between regions and to produce a scheduled physical power flow from the lower-cost region to the higher-cost region.

C. Settlement of Coordinated External Transactions.

Section III.3 of Market Rule 1 is being revised to reflect that the settlement interval for external transactions at interfaces for which Coordinated Transaction Scheduling is implemented will be 15 minutes.[67] The current settlement interval for all external transactions is one hour. As explained in the White-Dombrowski Testimony, if the settlement interval remains longer than the clearing interval, then the potential exists

[63] White-Dombrowski Testimony at pp. 25-26.

[64] *Id.* at p. 26.

[65] CTS Tariff Revisions at § III.1.10.7.A(c).

[66] White-Dombrowski Testimony at p. 27.

[67] CTS Tariff Revisions at § III.3.2.1.

that participants will face price risk for changes in LMPs during periods of the (longer) settlement interval during which the participant is not providing energy. Aligning the settlement interval with the clearing interval avoids this inefficient result.[68]

In addition, certain settlement values utilized in the 15-minute settlement calculations are calculated at the hourly level. In order for these values to be used in the 15-minute settlement calculation, the ISO will need to convert them into a 15-minute value. This will be done by equally apportioning the hourly value over the 15-minute settlement interval.[69] For example, a Day-Ahead Energy Market position of 40 MWh would be converted to four 15-minute increments by allocating 10 MWh to each 15-minute increment. This equal apportioning will be performed for internal bilateral transactions for purposes of determining a Real-Time Energy Market position [70] and for the Day-Ahead Energy Market position for purposes of determining net energy purchases and sales.[71]

In a similar vein, Section III.3.2.1(k) of the settlement rules is being clarified to indicate that, for purposes of the settlement calculation for Inadvertent Energy, which is the difference between the scheduled and actual energy flow into or out of the New England Control Area, the excess or deficiency in the energy calculation is to be summed from the 15-minute values to an hourly value.

D. Pricing Congestion under Coordinated Transaction Scheduling.

Congestion is a condition in which transmission system operating limits prevent unconstrained economic dispatch of the power system. Congestion is captured in the Congestion Component of the LMP. The Congestion Component of the LMP differs across locations within the New England transmission system whenever one (or more) internal transmission limits are binding.[72] Under the current inter-regional trading system, the ISO's External Transaction scheduling process does not generate the information necessary to establish an economically correct congestion price associated with a binding external interface limit. This is the result of the fact that ISO-NE and the NYISO do not exchange information about the marginal cost of power on their respective sides of the interface during the scheduling process.[73]

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[68] White-Dombrowski Testimony at pp. 31-32.

[69] CTS Tariff Revisions at § III.3.2.1(b).

[70] CTS Tariff Revisions at § III.3.2.1(b).

[71] CTS Tariff Revisions at § III.3.2.1(c).

[72] White-Dombrowski Testimony at p. 32.

[73] White-Dombrowski Testimony at p. 33. As a result, it is not possible for the ISO to evaluate the incremental change in the two systems' total production costs that would be realized with an additional unit of transmission capability between the two regions. Put in simple terms, the ISO

(continued...)

A benefit of the coordinated economic clearing process to be used for real-time Coordinated External Transactions under Coordinated Transaction Scheduling is that it will enable the ISO to set a congestion component for the external interface LMP when there is a binding external interface limit. As noted previously, the coordinated economic process of clearing an Interface Bid involves an exchange, or pooling, of each ISO's information about the impact of the Interface Bid on the incremental cost of sending (and receiving) another megawatt of power across the interface. When the external interface is binding at the time it is scheduled, the difference between one ISO's incremental cost of sending power and the other ISO's decremental cost of receiving power comprises the total congestion price across the interface. The ISOs propose to incorporate this difference, less the net amount paid to the marginal (*i.e.*, last accepted) Interface Bid, into the congestion component of their real-time LMP associated with an external interface under Coordinated Transaction Scheduling.[74]

To avoid both ISO-NE and the NYISO charging the total congestion price to participants (which would result in the double-counting of congestion charges), the total of the two regions' congestion components of the real-time LMPs associated with an external interface will add up to the desired total congestion price determined at the time the interface is scheduled, *viz.*, the difference between one ISO's incremental cost of sending power and the other ISO's decremental cost of receiving power, less the net amount paid to the marginal (*i.e.*, last accepted) Interface Bid.[75] The CTS Tariff Revisions address this in Section III.2.5(a), which states in relevant part that the Real-Time LMP associated with an external interface will be adjusted for the effect on New England congestion costs of a binding constraint limiting the external interface schedule.[76]

The CTS Tariff Revisions also enable congestion pricing in the Day-Ahead Energy Market at external interfaces that are subject to Coordinated Transaction Scheduling in real-time. Presently, the congestion component of the Day-Ahead Energy

(...continued)
does not calculate the correct real-time congestion price associated with a binding external interface today because the ISO does not possess the information this requires. Under the existing system, the ISO sets the congestion component of the real-time LMP associated with a binding external interface limit to zero. *Id.*at pp. 33-34.

[74] *Id.* at pp. 34-35.

[75] *Id.* at pp. 35-36. NYISO addresses this in its filing materials on page 13 of the transmittal letter for the NYISO CTS Filing.

[76] *See* the CTS Tariff Revisions at § III.2.5(a), which states in relevant part, "For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled."

Market LMP associated with a binding external interface limit is set to zero.[77] This means that, even if an external interface limit is binding when the Day-Ahead Energy Market clears, the congestion component of the Day-Ahead Energy Market LMP associated with the binding external interface is zero.[78]

The CTS Tariff Revisions remove administrative pricing of the congestion component of the Day-Ahead Energy Market LMP associated with an external interface limit, at external interfaces subject to Coordinated Transaction Scheduling.[79] This is desirable because the analogous congestion component of the real-time LMP will no longer be zero under Coordinated Transaction Scheduling, as described previously. Accordingly, there is no need for the ISO to administratively set the value of the corresponding congestion component of the day-ahead LMP to zero. Instead, it will be set by the bids and offers cleared in the Day-Ahead Market when the external interface limit binds.[80]

As a result of this change, the Day-Ahead Energy Market's congestion component will reflect the expected corresponding Real-Time congestion component. In effect, this change allows the Day-Ahead LMP to incorporate that market's expected frequency, and cost, of real-time congestion across the external interface, which may help participants to manage the costs of congestion through their day-ahead transactions.[81]

E. Eliminating Fee, Charge and Credit Eligibility under Coordinated Transaction Scheduling.

The ISO's proposed changes to its fees, charges, and credits under Coordinated Transaction Scheduling are narrowly focused on exempting affected external transactions

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[77] Section III.2.6(a) currently places "a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface." Revised Section III.2.5(a) explains that the constraint results in the interface limits for the limits being followed, but it makes clear that this constraint will have no impact on (i.e., will not increase the dollar value of) the congestion component of the LMP at the External Node.

[78] *See* White-Dombrowski Testimony at p. 37 ("The reason for this practice is to enforce consistency between the market models used to calculate prices in the Day-Ahead and Real-Time Energy Markets. As discussed previously, under the current inter-regional interchange system, the ISO does not have the information necessary to calculate a congestion component of the real-time LMP associated with a binding external interface limit, so by default sets that component to zero. Consistent with that practice, the ISO sets the analogous congestion component to zero in the Day-Ahead Energy Market.")

[79] CTS Tariff Revisions at § III.2.6(a), exempts Coordinated External Transactions from the application of the binding nodal constraint.

[80] White-Dombrowski Testimony at pp. 37-38.

[81] *Id.* at p. 38.

in an effort to eliminate cross-border transaction costs that inefficiently distort trade between regions and raise the total costs of operating the power systems.[82] It is anticipated that the reallocation of fees and charges as part of Coordinated Transaction Scheduling will lower total system costs overall, creating a greater benefit for the region than the reallocated costs.[83]

The ISO is proposing to eliminate the following fees, charges and credits. Note that because wheeling transactions are specifically excluded from the definition of Coordinated External Transactions, the following fees, charges and credits are not eliminated for transactions to wheel energy into, out of or through New England.

- Day-ahead and real-time Net Commitment Period Compensation ("NCPC") charges and credits, including (1) so-called "economic" NCPC charges for fees to support the posturing of resources, costs associated with cancelled starts, resources not dispatched in real time, and synchronous condensers, (2) "make whole" payments to resources that are committed and dispatched, (3) charges associated with a shortage of congestion revenue, and (4) other ancillary NCPC charges and credits.[84]

- Credits and charges associated with the purchase of energy from and the sale of energy to neighboring control areas in the event of an emergency.[85]

- Credits associated with the purchase of Security Energy, which is energy that is purchased from the New Brunswick System Operator to preserve minimum flows for transmission system reliability.[86] These credits are eliminated through excluding contributions from Coordinated External Transactions from the Real-

[82] This fee, charge and credit elimination is reciprocal with New York; comparable fees, charges and credits in the NYISO tariff are being eliminated for transactions that are subject to Coordinated Transaction Scheduling. *See* NYISO CTS Filing, transmittal letter at § IV.D. There is precedent for this type of reciprocal fee elimination. In 2004, the ISO filed to eliminate certain OATT charges on external transactions between New England and New York. That was also done on a reciprocal basis with the NYISO. *See ISO New England Inc.*, 109 FERC ¶ 61,147 (2004).

[83] While the allocation of ISO fees and charges to external transactions would seem to "save" load and other market participants from paying these fees, the White-Dombrowski Testimony presents an example to show how eliminating the allocation to external transactions may lower load's and other participants' total costs overall. *See* White-Dombrowski Testimony at pp. 16-17.

[84] *See generally* CTS Tariff Revisions at § III.3.2.3, and § III, Appendix F.

[85] CTS Tariff Revisions at § III.3.2.6.

[86] CTS Tariff Revisions at § III.3.2.6A.

Time Load Obligation for purposes of determining the Marginal Loss Revenue Load Obligation.[87]

- Credits and charges for Inadvertent Energy, which is the difference between the actual energy that flows and the scheduled energy that flows into or out of the New England Control Area. [88]

- Charges associated with the costs of Regulation service provided to New England.[89]

F. Conforming Changes to the Forward Capacity Market Rules.

As part of the Coordinated Transaction Scheduling project, the ISO is proposing revisions to the Forward Capacity Market rules, in order to align the scheduling obligations of New England Import Capacity Resources with the proposed Coordinated Transaction Scheduling design, and to simplify certain capacity import procedures for Market Participants with Import Capacity Resource obligations into New England that are associated with supply resources physically located in New York. The proposed revisions are limited in scope to the obligations of those Import Capacity Resources that (1) are associated with supply resources physically located in New York, and that (2) qualify in the Forward Capacity Market as an Import Capacity Resource across an external interface for which Coordinated Transaction Scheduling is implemented.[90]

There are two primary proposed changes to the Forward Capacity Market rules.[91] First, a New England Import Capacity Resource associated with a supply resource (*e.g.,* a generator) physically located in New York will be obligated to offer the resource and participate in the NYISO day-ahead and real-time energy markets, consistent with the obligations of a New York capacity resource.[92] In combination with the coordinated economic clearing process under Coordinated Transaction Scheduling, this requirement will help ensure the resource's output increases the net interchange schedule toward New England whenever the increase improves efficiency and lowers total production costs.[93]

Second, the Import Capacity Resource will no longer be obligated to offer a real-time import external transaction into the New England real-time energy market.[94] The

[87] CTS Tariff Revisions at § III.3.2.1(b)(v).

[88] CTS Tariff Revisions at § III.3.2.1(l).

[89] CTS Tariff Revisions at § III.3.2.2.

[90] White-Dombrowski Testimony at p. 41.

[91] *Id.*

[92] CTS Tariff Revisions at § III.13.6.1.2.3.

[93] White-Dombrowski Testimony at p. 42.

[94] CTS Tariff Revisions at § III.13.6.1.2.1.

Import Capacity Resource may choose to submit a real-time External Transaction in the form of an Interface Bid, but is not obligated to do so. This will simplify procedures for Market Participants with New England Import Capacity Resource obligations associated with supply resources physically located in New York.[95]

In addition, the CTS Tariff Revisions make conforming changes to the availability and deliverability penalties for Import Capacity Resources that are subject to Coordinated Transaction Scheduling.[96]

1. Requirement of New England Import Capacity Resources to Participate in New York's Energy Markets Consistent with New York Capacity Resource Requirements.

Requiring New England Import Capacity Resources associated with supply resources located in New York to adhere to the NYISO day-ahead and real-time energy market offer requirements applicable to New York capacity resources will ensure that the physical resource located in New York is available (committed by the NYISO) whenever it is expected to be economic the next Operating Day, and dispatched during the Operating Day whenever doing so contributes to an economic interchange schedule into New England enabled by Coordinated Transaction Scheduling. As Drs. White and Dombrowski explain in their testimony, energy produced within New York by a generator with a New England Import Capacity Resource obligation will effectively help serve load in New England when the LMP is higher in New England than in New York.[97] They offer the following example:

> Suppose that in the course of its normal internal dispatch, NYISO dispatches the New England Import Capacity Resource to a higher output level and, as a result, displaces production from a higher-cost generator in New York. This will tend to reduce New York's LMP. If New York's LMP is less than New England's LMP at the time, the reduction will widen the price spread across the external interface. Under the coordinated economic clearing process of Coordinated Transaction Scheduling, this wider price spread between regions will lead a greater quantity (in megawatts) of Interface Bids to be cleared, increasing the net interchange schedule toward New England.[98]

To fulfill this objective, the generator within New York with the Import Capacity Resource obligation must be dispatched by the NYISO based upon a competitive generation offer. To ensure the latter, the proposed tariff revisions require New England

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[95] White-Dombrowski Testimony at p. 42.

[96] CTS Tariff Revisions at §§ III.13.7.1.2.A, III.13.7.2.7.2.1, III.13.7.2.7.2.2(a)..

[97] White-Dombrowski Testimony at p. 43.

[98] *Id*.

Import Capacity Resources physically located in New York (that qualified at an external interface subject to Coordinated Transaction Scheduling) to participate in the NYISO's energy markets, consistent with the obligations of a New York ICAP resource.[99]

2. Removing the Real-Time Energy Market Offer Component for Import Capacity Resources.

Under the current system, a Market Participant with a New England Import Capacity Resource obligation is required to submit a real-time External Transaction import offer into New England. In addition, the import offer price is subject to an offer price cap. Together, these requirements are termed a "competitive offer" requirement for Import Capacity Resources.[100] Under the CTS Tariff Revisions, Import Capacity Resources subject to Coordinated Transaction Scheduling will no longer be obligated to offer a real-time import External Transaction into the New England Real-Time Energy Market, and thus no "competitive offer" price cap will apply.[101]

Requiring an Import Capacity Resource to submit a real-time Interface Bid is unnecessary under the Coordinated Transaction Scheduling design that requires the associated generation facility in New York to participate competitively (*i.e.*, consistent with its competitive reference level) in the NYISO energy markets. The NYISO will evaluate the generation facility for commitment in the energy market, and it will be committed when economic. Once online, the facility's generation supply offer will be incorporated in NYISO's market offer data used by the coordinated economic clearing process to determine the net interface schedule.[102]

The economic design of the Coordinated Transaction System is also structured so that market participants will, in the aggregate, submit many Interface Bids each scheduling interval. Interface Bids may be submitted by any market participant, and they are costless to submit. This is because both ISOs are eliminating their cross-border transaction costs, as described previously. In addition, the coordinated economic clearing process for each Interface Bid ensures that a bid will be cleared only if the bidder's expected net profit exceeds the bid price. A participant that clears an Interface Bid with a positive bid price is expecting to "buy low" in one region and "sell high" in the other. By design, in doing so, the cleared Interface Bid increases the net interchange schedule from the low-to-high price region. This alignment of market participants' private economic interests with the broader societal interest in minimizing the two regions' combined production costs creates a market incentive for participants to submit, in the aggregate, a

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[99] CTS Tariff Revisions at § III.13.6.1.2.3.

[100] Market Rule 1 at § III.13.6.1.2.1. The offer prices of real-time External Transactions into New England from participants without an Import Capacity Resource obligation are not subject to this requirement.

[101] White-Dombrowski Testimony at p. 45.

[102] *Id.*

large quantity of Interface Bids between regions—rendering it unnecessary for a participant with an Import Capacity Resource to be required to submit an Interface Bid.[103]

Finally, requiring an Import Capacity Resource to submit an Interface Bid into New England would have no effect at all unless it also capped the submitted Interface Bid price at or *below* the market-clearing (that is, marginal) price of all accepted Interface Bids. This is because any Interface Bid submitted above the market-clearing price will not clear, and therefore will not affect the quantity of power scheduled across the external interface. Given the anticipated competitive nature of Interface Bids, placing an obligation upon a Market Participant to submit an Interface Bid capped at a bid price that is *below* the market-clearing price of all accepted Interface Bids may produce an undesirable market distortion in and of itself.[104]

3. Conforming Changes to Availability and Deliverability Penalties.

The CTS Tariff Revisions also make conforming changes to the provisions for several existing penalties. The purposes of such penalties, and the associated penalty rates, are unchanged. In brief, the rationale for the conforming changes to the existing penalty provisions are:

- **Failure to Offer.** Under the current market rules, a failure to offer occurs, under the provisions contained in Section III.13.7.2.7.2.1(a) and (b), if a New England Import Capacity Resource fails to submit a real-time and day-ahead external transaction import offer, or if such import offer does not meet the offer requirements, including the quantity (megawatt) and compliance with the offer price cap as required by the "competitive offer" requirement.[105]

  As discussed previously, the CTS Tariff Revisions remove the requirement that New England Import Capacity Resources physically located in New York (that qualified at an external interface at which Coordinated Transaction Scheduling is implemented) submit a real-time external transaction import offer. Accordingly, the failure to offer penalty will no longer apply in the event such a resource does not submit a real-time external transaction (Interface Bid) import offer.[106]

[103] *Id.* at pp. 46-47.

[104] *Id.* at p. 47.

[105] *Id.* at p. 48.

[106] *Id.* The proposed revisions retain the existing offer requirement and associated failure-to-offer penalty provisions for Day-Ahead external transaction import offers from New England Import Capacity Resources, at all external interfaces.

- **Failure to deliver.** Under the current provisions contained in Section III.13.7.2.7.2.1(c), the failure-to-deliver penalty occurs when energy associated with a capacity resource is not delivered into New England across an external interface when the ISO clears the associated real-time external transaction import. This can occur for several different reasons, including a "check out" failure of the associated real-time external transaction (submitted separately to each ISO), or the Import Capacity Resource supply resource in the source region being offline during a period when the source region is experiencing an operating reserve deficiency.[107]

  For New England Import Capacity Resources physically located in New York and subject to Coordinated Transaction Scheduling, the deliverability obligation will continue to exist, but "check out" failures will no longer be relevant. Under Coordinated Transaction Scheduling, if upon the ISO's request the NYISO indicates that the total quantity of energy that may be delivered to New England is limited (to an amount less than the request) because one (or more) Import Capacity Resources are not available or deliverable to New England, and this limit constrains the net interchange determined during coordinated economic clearing, then the Import Capacity Resources that are not deliverable are subject to the existing failure-to-deliver penalty provisions.[108] Otherwise, Import Capacity Resources that are subject to Coordinated Transaction Scheduling will not be assessed failure-to-deliver penalties.[109]

- **Shortage Event Penalty.** The existing shortage event penalty will continue to apply to New England Import Capacity Resources. Eligibility for this penalty is ascertained, in the event of an FCM Shortage Event, similarly to the process for ascertaining eligibility of a failure to deliver penalty for Import Capacity Resources at an external interface for which the ISO has implemented Coordinated Transaction Scheduling. Today, the ISO reviews the delivery performance of the Import Capacity Resource's real-time external transaction import offer. Under Coordinated Transaction Scheduling, the ISO will review information regarding the actual operation of the Import Capacity Resource's associated supply resource (*e.g.*, a generator) physically located in New York during the Shortage Event.[110]

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

[108] *Id.* at pp. 49-50. Certain existing exemptions to this penalty, such as non-deliverability due to binding transmission limits across the relevant external interface, will remain in place.

[109] CTS Tariff Revisions at §§ III.13.7.2.7.2.1, III.13.7.2.7.2.2(a).

[110] White-Dombrowski Testimony at p. 50. *See* CTS Tariff Revisions at § III.13.7.1.2.A.

VII. PROVISIONS TO EVALUATE PERFORMANCE OF COORDINATED TRANSACTION SCHEDULING.

As explained above, the CTS Tariff Revisions include a procedure to evaluate the success of Coordinated Transaction Scheduling at one- and two-year time intervals based upon specified performance standards.[111] In the event it is determined that Coordinated Transaction Scheduling does not meet those performance standards, the procedure provides for a process for either modifying Coordinated Transaction Scheduling to address any issues or, should that not be possible, to replace Coordinated Transaction Scheduling with the alternative scheduling procedure proposal developed by the ISO and NYISO, referred to as Tie Optimization.[112] Under this procedure, any Tariff revisions to modify Coordinated Transaction Scheduling or replace it with Tie Optimization would be filed with the Commission as a compliance filing to the CTS Tariff Revisions filed herewith to implement Coordinated Transaction Scheduling.

As the NYISO indicates in the NYISO CTS Filing with respect to its parallel provision, the evaluation procedure in Section III.1.10.7.B "is designed to balance the preferences of stakeholders in ISO-NE and the NYISO and to allow the Commission to consider the [Coordinated Transaction Scheduling] proposal, which is expected to bring substantial improvements to the efficiency of Energy trading, sooner than would otherwise be possible."[113]

The evaluation procedure in Section III.1.10.7.B requires the External Market Monitor to perform a review of the production costs savings of Coordinated Transaction Scheduling after it has been in effect between New England and New York for two years (the "two-year analysis"), and to present the results of its analysis to New England stakeholders for their review and comment.[114] This production costs saving review will evaluate whether Coordinated Transaction Scheduling meets the thresholds defined in Section III.1.10.7.B(b), which were developed by the External Market Monitor and presented to the New England and New York stakeholders for their consideration.[115] If ISO-NE determines, based upon the evaluation of the External Market Monitor and considering the input of the New England Stakeholders, that the thresholds in Section

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[111] CTS Tariff Revisions at § III.1.10.7.B.

[112] CTS Tariff Revisions at § III.1.10.7.B(a). Tie Optimization is described in Section III of the Joint ISO White Paper.

[113] NYISO CTS Filing, transmittal letter at p. 16.

[114] CTS Tariff Revisions at § III.1.10.7.B(b).

[115] David B. Patton, PhD, Potomac Economics, *Potential Trigger to Switch from CTS to TO*, August 9, 2011, included as an attachment to this filing, and presented to New England stakeholders at the September 9, 2011 NEPOOL Participants Committee meeting. *See* Minutes of the September 9, 2011 NEPOOL Participants Committee meeting ("EMM Trigger Presentation").

III.1.10.7.B(b) have not been met, ISO-NE, in conjunction with the External Market Monitor and considering the input of the New England Stakeholders, would identify and implement improvements to Coordinated Transaction Scheduling (the "CTS Improvements").[116]

One year after the CTS Improvements are implemented, a second analysis (the "one-year review") by the External Market Monitor would be conducted and presented to New England stakeholders for their review and comment, using the same thresholds identified above.[117] If, as a result of the one-year review, ISO-NE determines, based upon the evaluation of the External Market Monitor and considering the input of the New England Stakeholders, that the thresholds have not been met, Section III.1.10.7.B(d) requires that the ISO develop and file Tariff revisions to implement Tie Optimization, absent the ISO-NE and the NYISO discovering a "superior alternative" that could be developed in place of Tie Optimization.

There are two specific savings thresholds that will be evaluated by the External Market Monitor for the two-year analysis and follow-up one-year review.[118] The first threshold examines whether the foregone production cost savings that would have accrued during the evaluation period under the Tie Optimization alternative, relative to the Coordinated Transaction Scheduling system, are less than $3 million per year. The purpose of this threshold is to indicate a *de minimis* assessment of the production cost savings that may be expected to accrue from a switch to the Tie Optimization alternative.

The second threshold examines whether the "Tie Optimization Savings" is 60%, or less, of the additional production cost savings under a "perfect information" scheduling system.[119] The "perfect information" calculation evaluates forgone production cost savings that would have accrued during the evaluation period if the ISO and the NYISO were able to perfectly foresee all contingencies, LMP changes, and other uncertainties that affect the efficiency of interchange scheduling *ex post*. The rationale for this threshold is that the absence of perfect information will tend to create risk for market participants under Coordinated Transaction Scheduling, which may appear as "Tie Optimization Savings" when in fact the risks would exist, in part, under the Tie Optimization system as well.[120]

As the NYISO explains in the NYISO CTS Filing with respect to its parallel provision, the evaluation mechanism in Section III.1.10.7.B "has been structured to

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[116] CTS Tariff Revisions at § III.1.10.7.B(c).

[117] CTS Tariff Revisions at § III.1.10.7.B(d)(1).

[118] *See* the CTS Tariff Revisions at § III.1.10.7.B(c) and (d).

[119] In the EMM Trigger Presentation, the External Market Monitor refers to the "perfect information" scheduling system as the "Ideal Case."

[120] *See* EMM Trigger Presentation, at Slide 4.

provide ample opportunity for Market Participants to be fully involved in these reviews and analyses and in reaching final decisions."[121] Stakeholder review and comment in evaluation analyses and potential tariff improvements under Section III.1.10.7.B include: i) the External Market Monitor's presentation of its two-year analysis; ii) the development of Coordinated Transaction Scheduling improvements following the two year review, if any; iii) the External Market Monitor's presentation of its one-year analysis; iv) ISO-NE's consideration of whether a "superior alternative" has emerged; and v) development of Tariff amendments describing Tie Optimization.

VIII. STAKEHOLDER PROCESS.

The stakeholder process for consideration of the Coordinated Transaction Scheduling tariff revisions filed herein began at the September 13-14, 2011 NEPOOL Markets Committee meeting. These rule changes were discussed over the course of four meetings during the fall of 2011. The Markets Committee, at its December 6-7, 2011 meeting, voted to recommend that the NEPOOL Participants Committee support the CTS Tariff Revisions with a vote of 94.23% in favor.[122] Following Markets Committee consideration and recommendation of the market rule changes, the matter was presented to the Participants Committee for its consideration and vote. The Participants Committee, at its January 20, 2011 meeting, unanimously supported the CTS Tariff Revisions as part of its Consent Agenda.[123]

IX. ADDITIONAL SUPPORTING INFORMATION.

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[124]

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[121] NYISO CTS Filing, transmittal letter at p. 16.

[122] The individual Sector votes were Generation (17.3% in favor, 0% opposed, 3 abstentions), Transmission (17.3% in favor, 0% opposed, 1 abstention), Supplier (11.53% in favor, 5.77% opposed, 6 abstentions), Alternative Resources (13.5% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (17.3% in favor, 0% opposed), and End User (17.3% in favor, 0% opposed, 1 abstention).

[123] 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. Although voted as a single motion, 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 January 20, 2012 Consent Agenda included its support for the Coordinated Transaction Scheduling tariff revisions.

[124] 18 C.F.R. § 35.13 (2011).

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

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

- This transmittal letter;
- Blacklined ISO Tariff sections reflecting the revisions submitted in this filing;
- Clean ISO Tariff sections reflecting the revisions submitted in this filing;
- Joint Testimony of Drs. Matthew White and Janine Dombrowski (the "White-Dombrowski Testimony"), sponsored solely by the ISO;
- Presentation of David B. Patton, PhD, Potomac Economics, *Benefits of Coordinating the Interchange Between New York and New England*, January 21, 2011;
- Presentation of David B. Patton, PhD, Potomac Economics, *Potential Trigger to Switch from CTS to TO*, August 9, 2011;
- *ISO New England Inc. and New York Independent System Operator, Inc. White Paper* on *Inter-Regional Interchange Scheduling: Analysis and Options* (January 5, 2011) (the "Joint ISO White Paper"); and
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Section I above, the Filing Parties request that the revisions become effective on or after August 1, 2013, with two weeks' prior notice to be provided by the ISO for the actual effective date.

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

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

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

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

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

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

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

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

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

X. CONCLUSION.

As explained herein, Coordinated Transaction Scheduling was developed to enhace the market efficiency of external transactions between New England and New York, and has the potentiaon to produce significant reductions in production costs and energy expenditures. Accordingly, the ISO and NEPOOL request that the Commission accept this filing with the revisions to become effective on or after August 1, 2013, with two weeks' prior notice to be provided by the ISO for the actual effective date..

Respectfully submitted,

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I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

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

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

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

Adjusted Regulation Obligation is equal to a Market Participant’s total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

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

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

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

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

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

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

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

AGC is automatic generation control.

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

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

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

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

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (v) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

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

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

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

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Capacity Requirement is a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as described in Section III.13.7.3.1 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.9.5.3.

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.9.5.3.

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

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

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

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

Commission is the Federal Energy Regulatory Commission.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Control Area, for purposes of Section II of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

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

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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

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

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

Cost of New Entry (CONE) is determined in accordance with Section III.13.2.4 of Market Rule 1.

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

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

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

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

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

Critical Peak Demand Resource is a type of Demand Resource, and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

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

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

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

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

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

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

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

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

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand.

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

Demand Reduction Value is the quantity of reduced demand, measured at the Retail Delivery Point for the end-use customer, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

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

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

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

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

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

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

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

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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

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

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

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

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

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

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

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

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

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

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

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

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

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

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

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

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

Emergency, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

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

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

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

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

EMS is energy management system.

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

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

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

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

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

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

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

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

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

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

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

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the Retail Delivery Point for the end-use customer that can be produced by a Critical Peak Demand Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, in each hour of an Operating Day.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets, 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.

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

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

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

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

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

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

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

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

Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.8.3.1.

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

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

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

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

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

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

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

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

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

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

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

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

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

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

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

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

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

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

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

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

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

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

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

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

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the

Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

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

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

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

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

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

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

LSE means load serving entity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a Real-Time Demand Response Asset.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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

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

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

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

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

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

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

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

MUI is the market user interface.

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

MWh is megawatt-hour.

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

NCPC Charge means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

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

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

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

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

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

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone’s Local Sourcing Requirement, as described in Section III.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 2010) and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

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

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

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

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

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

New England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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

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

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

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

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

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

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

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

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

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

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

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

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

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

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

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

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

Other Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects 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 specified ODR performance hours of the ICAP Transition Period.

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

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

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

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

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

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

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

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

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

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

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

Payment is a sum of money due to a Covered Entity from the ISO, as remitting agent for the Covered Entities.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Posturing Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E.8.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours.

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

Real-Time Demand Response Event Hours means the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

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

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that (i) reports the load as measured at the Retail Delivery Point, and, if there are other assets located behind the Retail Delivery Point, reports the output of one or more emergency generators as a single set of values, (ii) is assigned a unique asset identification number by the ISO, and (iii) participates in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response holidays in which the ISO dispatches Real-Time Emergency Generation Resources to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a Load Zone or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. Beginning on June 1, 2011, Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

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

Real-Time Energy Market means the purchase or sale of energy, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

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

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

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

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

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

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

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

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

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

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.
Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

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

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

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

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

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

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

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

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

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the

New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Re-Offer Period is the period normally between 16:00 and 18:00 on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

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

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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

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

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

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

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

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

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

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

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

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

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

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

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

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

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

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

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STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 shall become effective on the Operations Date.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 [Reserved.]

III.1.5 [Reserved.]

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 General.

III.1.7.1 [Reserved.]

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

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

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

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

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

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

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

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

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

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

III.1.7.7 Energy Pricing.

The price paid for energy bought and sold in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule 1 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 by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 [Reserved.]

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1.

Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Regulation.

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

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

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

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

III.1.7.19 Ramping.

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

III.1.7.19A Real-Time Reserve.

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

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

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

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: 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 & ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the ISO New England Manuals and ISO New England Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

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

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

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

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

(b) [Reserved.]

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

Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the re-offer period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

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

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

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $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 1. Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

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

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

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

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

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

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

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

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

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

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

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

(f) Each Market Participant owning or controlling the output of 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 superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days.

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

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

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

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

III.1.10.2 Pool-Scheduled Resources.

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

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

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

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

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees and No-Load Fee, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized ("Cancellation Fee").

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

(f) Eligibility for NCPC in the Day-Ahead Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(g) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(h) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule 1.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule 1.

III.1.10.3 Self-Scheduled Resources.

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

(a) [Reserved.]

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

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling any portion of that Resource.

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

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

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

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

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

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

III.1.10.6 Dispatchable Asset Related Demand Resources.

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

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

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

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

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

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

(f) abide by the ISO maintenance coordination procedures;

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

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

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

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

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

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the re-offer period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by noon prior to the Operating Day for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the re-offer period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by noon prior to the Operating Day for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the re-offer period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

(iii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iv) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

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

III.1.10.7.A Coordinated External Transactions.

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

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

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

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

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

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System

Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1..10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the "foregone" bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term "b." The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term "a."

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

$$b/a$$

If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.

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

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

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

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

III.1.10.9 Hourly Scheduling.

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

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

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

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

(c) During the re-offer period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the re-offer period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(d) **[Reserved.]**

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

III.1.11 Dispatch.

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

III.1.11.1 Resource Output.

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

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative

Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

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

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

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

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to 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.1.11.5 Regulation.

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

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim Regulation Clearing Price is then calculated and the Regulation Rank Prices are updated using this interim Regulation Clearing Price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

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

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

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

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

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

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

(iii) To more accurately estimate the actual Regulation Opportunity Cost that will be paid, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.

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

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

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

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

LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit), And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

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

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

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

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

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

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

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

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

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

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

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

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

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

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

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource submitted under Section III.1.10.7 and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

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

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

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

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase submitted under Section III.1.10.7 or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

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

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

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

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

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

(c) In determining whether a generating Resource or External Transaction purchase submitted under Section III.1.10.7 satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

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

(e) Coordinated External Transactions are not evaluated for purposes of the calculations detailed in this Section III.2.4.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

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

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

III.2.6 Calculation of Day-Ahead Nodal Prices.

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

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

~~The process for clearing External Nodes differs from the process for clearing other Nodes in that~~For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply:~~,~~ in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

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

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

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

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

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

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

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

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

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

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

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

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

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

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

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

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

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

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

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer’s knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

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

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

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

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

(i) local TMOR RCPF = $250/MWh;
(ii) system TMOR RCPF = $100/MWh;
(iii) system TMNSR RCPF = $850/MWh;
(iv) system TMSR RCPF = $50/MWh.

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

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

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

III.2.8 Hubs and Hub Prices.

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

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

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

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

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

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

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

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

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

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

III.2.9B Final Day-Ahead Energy Market Results

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

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

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

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

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

III.3 Accounting And Billing

III.3.1 Introduction.

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

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for external interfaces for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented shall be 15 minutes, and the settlement interval for all other Locations shall be one hour.

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

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

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

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

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

(b) For each Market Participant for each ~~hour~~settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

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

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each ~~hour~~ settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the

Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) For each Market Participant for each ~~hour~~settlement interval, the ISO will determine the difference between the Day-Ahead Energy Market position (Section III.3.2.1(a)) and the Real-Time Energy Market position (Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

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

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

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

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

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

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

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

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

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each ~~hour~~ settlement interval multiplied by the difference between the Loss Component of the ~~hourly~~ Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the ~~hourly~~ Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each ~~hour~~settlement interval, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price~~ and then summing these values for all External Nodes~~. The resulting excess or deficiency in Inadvertent Energy Revenue at each External Node shall then be summed to determine a single hourly value for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The

Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

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

III.3.2.2 Regulation.

(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly Regulation obligation through its own Resources or through an appropriate bilateral transaction, shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (j) of this Section. Notwithstanding the foregoing, the calculation of Regulation charges under this Section III.3.2.2 shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

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

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

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

(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time-weighted average of all interval based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Section III.2.9A of this Market Rule 1.

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

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

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

(i) In determining the credit under subsection (b) to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit-specific

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

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

III.3.2.3 NCPC Credits.

The following paragraphs describe the calculation of NCPC Credits and NCPC Charges. Additional information on these calculations may be found in Appendix F of this Market Rule 1.

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

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

(i) For each generating Pool-Scheduled Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start-Up Fees and No-Load Fee and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, if the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

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

(c) Except as otherwise provided for under Section III.F.3, the sum of the foregoing credits calculated in accordance with Section III.3.2.3(b) shall be the "NCPC Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F. Notwithstanding anything to the contrary in this Section III.3.2.3, Coordinated External Transactions shall be excluded from the Day-Ahead Energy Market NCPC Charge calculation.

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

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

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

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

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

(f) A Market Participant's Pool-Scheduled Resource or Self-Scheduled generating Resource, the output of which is reduced or suspended at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve or for the provision of voltage support, shall be credited in an amount equal to the following:

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

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

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

AG equals the actual output of the generating Resource;

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

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

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

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

(g) Except as otherwise provided for under Section III.F.3, the sum of the foregoing NCPC Credits, plus any Cancellation Fees paid in accordance with Section III.1.10.2(d), such Cancellation Fees to be applied to the Operating Day for which the unit was scheduled, shall be the non-synchronized condensing NCPC Charge for the Real-Time Energy Market in each Operating Day.

(h) The non-synchronized condensing and synchronized condensing NCPC Charge for the Real-Time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Notwithstanding the foregoing, Coordinated External Transactions shall be excluded from the Real-Time Energy Market NCPC Charge calculation. For the purposes of calculating generation deviations, if a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating Real-Time NCPC Charges. For the purposes of calculating Real-Time NCPC Charges, any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation.

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

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

(k) ~~**[Reserved]**~~ Market Participants shall not be eligible to receive Day-Ahead NCPC Credits or Real-Time NCPC Credits for Coordinated External Transactions.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

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

Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs attributable to the purchase of Emergency energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

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

III.3.2.6A New Brunswick Security Energy.

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

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 of this Market Rule 1, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

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

III.3.4.2 Transmission Losses.

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

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter

Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.5 Transmission Congestion Revenue & Credits Calculation

III.5.1 Non-Market Participant Transmission Congestion Cost Calculation.

III.5.1.1 Calculation by ISO.

When the transmission system is operating under constrained conditions, the ISO shall calculate Congestion Costs.

III.5.1.2 General.

The basis for the Congestion Costs shall be the differences in the Congestion Component of the Locational Marginal Prices between points of delivery and points of receipt, as determined in accordance with Section III.2 of this Market Rule 1.

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation.

Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each ~~hour~~ settlement interval multiplied by the difference between the Congestion Component of the ~~hourly~~ Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the ~~hourly~~ Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using TOUT Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility.

Except as provided in Section III.A.8.4 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the FTRs held at the time of the constrained hour.

(b) FTRs shall be awarded to winning bidders in the FTR Auctions pursuant to Section III.7.

(i) An entity that acquires an FTR through the FTR Auction shall automatically be recognized by the ISO as the registered FTR Holder of that FTR, subject to having already met the eligibility criteria for bidding in the FTR Auction. The registered FTR Holder shall be entitled to receive or be obligated to make FTR payments arising from such FTR in accordance with Section III.5.2.

(ii) An entity that acquires an FTR through the FTR Auction may elect to hold it, or sell it in the FTR Auction. The ISO shall settle FTRs only with the registered FTR Holders. At any given time, each FTR shall have only one registered FTR Holder.

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders.

A target allocation of Transmission Congestion Credits for each FTR Holder shall be determined for all applicable FTRs. Each FTR shall be multiplied by the Day-Ahead Price Congestion Component differences for the associated receipt and delivery points. This calculation will result in a positive or negative FTR target allocation. All negative target allocations are obligations to pay. All positive target allocations will be summed for an FTR Holder for the month and compensated as Transmission Congestion Credits under Section III.5.2.5.

III.5.2.5 Calculation of Transmission Congestion Credits.

(a) The total Transmission Congestion Revenue available for the month shall be equal to the sum of: (i) the hourly Day-Ahead Congestion Revenue amounts for the month, (ii) the hourly Real-Time Congestion Revenue amounts for the month plus Congestion Costs collected under Section III.5.1.4, and (iii) the negative FTR target allocations calculated under Section III.5.2.4.

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

(c) If the sum of all the monthly positive target allocations is greater than the Transmission Congestion Revenue for the current month, each FTR Holder shall be assigned a share of the total Transmission Congestion Revenue for the current month in proportion to its total monthly positive target allocations.

III.5.2.6 Distribution of Excess Congestion Revenue.

If there is any Transmission Congestion Revenue at the end of the calendar year, this amount shall be proportionally allocated to any remaining unpaid monthly positive target allocations plus interest on the unpaid monthly positive target allocations in the months of that year, but shall not exceed an amount equal to the unpaid monthly positive target allocation plus interest on the unpaid monthly positive target allocations in the months of the calendar year. Any remaining surplus Transmission Congestion Revenue shall be allocated to the entities who paid Congestion Costs in that calendar year in proportion to the amount of total Congestion Costs paid during the year.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals and Capacity Load Obligation Bilaterals in accordance with this Section III.13.5. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

A resource having a Capacity Supply Obligation seeking to shed that obligation ("Capacity Transferring Resource") may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part ("Capacity Supply Obligation Bilateral"), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated ("Capacity Acquiring Resource"), subject to the following limitations

(a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) The Capacity Transferring Resource and the Capacity Acquiring Resource that are parties to a Capacity Supply Obligation Bilateral must be located in the same Capacity Zone, or the path from the Capacity Transferring Resource to the Capacity Acquiring Resource must flow across adjacent Capacity Zones in the direction of the modeled interface constraint(s), as such Capacity Zones and interface constraints are defined following the Forward Capacity Auction conducted for the Capacity Commitment Period to which the transferred Capacity Supply Obligation applies.

(g) If the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating Procedures. The ISO will issue a submission schedule for annual Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. Monthly Capacity Supply Obligation Bilaterals may only be submitted and confirmed after the results of the third annual reconfiguration auction have been issued (except as described in Section III.13.4.2.1.3(c)) and prior to the closing of the monthly Capacity Supply Obligation Bilateral window, which will occur prior to the monthly reconfiguration auction. ISO New England will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO during the same submittal window and no later than the same deadline that applies to submission of the Capacity Supply Obligation Bilateral.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met.

(b) Each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation outage information, and will include transmission security studies. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource. The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation ("Capacity Load Obligation Transferring Participant") may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone ("Capacity Load Obligation Bilateral") to any Market Participant seeking to acquire a Capacity Load Obligation ("Capacity Load Obligation Acquiring Participant"). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

Only Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented) and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for the entire term indicated in the designation described in Section III.13.5.3.1.2.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must be located in the same Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Bilateral, a Supplemental Availability Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the resource’s Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource’s Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource’s Real-Time Reserve Designations of TMNSR and TMOR and the Supplemental Capacity Resource’s Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability Bilateral does not affect in any way either party’s Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Bilateral is to modify the Supplemented Capacity Resource’s availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource's notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with good utility practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;

(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.

The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to 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 Certain Import Capacity Resources.

~~Import Capacity Resources are subject to the following additional requirements: ~~The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.

Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with the requirements in this Section III.13.6.1.2.3 may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

(a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.

(b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.1.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.

(c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.

(d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.
Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.
Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

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. Resources without a Capacity Supply Obligation.
A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. Energy Market Offer Requirements.
A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.
A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO dispatch instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.
A Generating Capacity Resource having no Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, must Self-Schedule in order to participate in the Real-Time Energy Market and shall be subject to all of the

requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.

Settlement Only Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.

Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

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 subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that capacity that is not subject to a Capacity Supply Obligation. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a resource.

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period ("Obligation Month"), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource's availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource's availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.

(b) In an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone.

(c) An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource's hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource's Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource's hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO's annual maintenance scheduling process~~.~~ or, for resources in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented, when a Market Participant notifies the ISO, in accordance with the ISO's annual maintenance scheduling process, that an asset associated with the External Resource is on an outage that was approved in the resource's native Control Area. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource's hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in this subsection~~:~~.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource's performance.

III.13.7.1.2. Import Capacity.

The provisions of this Section III.13.7.1.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1~~, as appropriate~~). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section

III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.1.3.7.1.2.A. Import Capacity on External Interfaces with Enhanced Scheduling.

The following available MW determination applies to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as designed in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.A.1). The available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation in the interval when the ISO requested delivery.

(b) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the available MW of a resource within that Control Area in the interval when the ISO requested delivery and that contains any portion of a Shortage Event shall be established as follows:

(i) The quantity available is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

(ii) The quantity available is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested delivery.

(c) If the ISO does not request MW of Import Capacity Resources, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation.

III.13.7.1.2.A.1. Availability Adjustments.

When the available MW of an Import Capacity Resource is calculated under Section III.13.7.1.2.A(b), the hourly availability score of any such Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource has complied with the provisions in Section III.13.7.1.1.4(b) for outage scheduling.

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012, the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First and Second Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section

III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is the quantity of reduced demand, calculated at the Retail Delivery Point, produced by a Demand Resource. All Demand Reduction Values are based on reductions in end-use demand on the electricity network in the New England Control Area coincident with Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, Demand Resource Critical Peak Hours for Critical Peak Demand Resources, Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, or Real-Time Emergency Generation Event Hours for Real-Time Emergency Generation Resources. The Demand Reduction Value of a combined Demand Resource that reduces load and generates output simultaneously for a single facility shall be its Average Hourly Output, which reflects the combined impact of the load reduction and Distributed Generation output on reducing overall end-use demand on the electricity network in the New England Control Area.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month. Should a new On-Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be based on the Demand Reduction Value established for the previous month. Should a new Seasonal Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan. A Seasonal Peak Demand Resource supplier 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 Demand Resource Seasonal Peak Hours, provided that the audit results shall not supplant the summer or winter seasonal Demand Reduction Value based on Demand Resource Seasonal Peak Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values for all subsequent months until the month in which Demand Resource Seasonal Peak Hours occur, provided, however, that audit results can not be used to determine the Demand Reduction Value for a month greater than twelve (12) months from the date the audit was conducted. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan set forth in Section III.13.1.4.2.2.3.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. Calculation of Demand Reduction Values for Critical Peak Demand Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December and January, the Demand Reduction Value of Critical Peak Demand Resource shall be equal to its Average Hourly Load Reduction or Average Hourly Output during Demand Resource Critical Peak Hours in the month. If there are no Demand Resource Critical Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Critical Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, as described above, then the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Critical Peak Demand Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Demand Resource Critical Peak Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Demand Resource Critical Peak Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values for all subsequent months until the month in which Demand Resource Critical

Peak Hours occur, provided, however, that audit results can not be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan, as set forth in Section III.13.1.4.2.2.3.

III.13.7.1.5.6.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Critical Peak Demand Resource for September, October, November, April and May shall be equal to:

(i) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of June, July and August if there are no Demand Resource Critical Peak Hours in the month or

(ii) the simple average of:

(a) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of June, July and August and

(b) its Average Hourly Load Reduction or Average Hourly Output across the Demand Resource Critical Peak Hours in the month if there are Demand Resource Critical Peak Hours in the month.

III.13.7.1.5.6.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Critical Peak Demand Resource for February and March shall be equal to:

(i) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of December and January if there are no Demand Resource Critical Peak Hours in the month or

(ii) the simple average of:

(a) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of December and January and

(b) its Average Hourly Load Reduction or Average Hourly Output across the Demand Resource Critical Peak Hours in the month if there are Demand Resource Critical Peak Hours in the month.

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Real-Time Demand Response Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values for the Real-Time Demand Response Resource, then the missing data shall be supplemented with audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Real-Time Demand Response Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Real-Time Demand Response Event Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Real-Time Demand Response Event Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values of a Real-Time Demand Response Resource for all subsequent months until the month in which Real-Time Demand Response Event Hours occur, provided, however, that audit results cannot be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan pursuant to Section III.13.1.4.2.2.3.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event

Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Real-Time Emergency Generation Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values for the Real-Time Emergency Generation Resource, then the Demand Reduction Value shall be established using audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Real-Time Emergency Generation Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Real-Time Emergency Generation Event Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Real-

Time Emergency Generation Event Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values of a Real-Time Emergency Generation Resource for all subsequent months until the month in which Real-Time Emergency Generation Event Hours occur, provided, however, that audit results cannot be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan, pursuant to Section III.13.1.4.2.2.3.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011, in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

III.13.7.2. Payments and Charges to Resources.

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

III.13.7.2.1. Generating Capacity Resources.

III.13.7.2.1.1. Monthly Capacity Payments.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a

Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward

Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Charge Amount to Capacity Load Obligations in the Capacity Zone where Resource is located = Capacity Clearing Price $_{\text{location of the resource}}$ x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = Capacity Clearing Price $_{\text{location of the resource}}$ x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE’s Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.

An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1. Demand Resources shall be subject to Demand Resource Performance Penalties and Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f). Real-Time Emergency Generation Resources shall be subject to Demand Resource Performance Penalties and Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-

Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E.9.2.1 or III.E.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) **Per Day**. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month**. The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period**. In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for Capacity Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the ~~following~~provisions in (a) and (b) below. In addition, all Import Capacity Resources will be subject to the provisions in (c) below~~:~~.

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b)~~ for any amount that was unavailable due to an outage approved in the ISO's annual maintenance scheduling process~~.

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction submitted under Section III.1.10.7 and associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

For Import Capacity Resources with a Capacity Obligation at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented (unless the Import Capacity

Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.), the requested and delivered MW are determined as follows:

(i) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the resources within that Control Area will not be evaluated for penalties.

(ii) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the resources will be evaluated using the following requested and delivered MW values:

1. The quantity requested is the resource's Capacity Supply Obligation; and
2. The quantity delivered for a resource is determined as follows:
   a. The quantity delivered is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;
   b. The quantity delivered is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested deliver;
   c. For purposes of this determination, the total energy delivered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(iii) If the ISO does not request MW of Import Capacity Resources, then the resources within that Control Area will not be evaluated for delivery penalties.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

The exceptions in Sections III.13.7.2.7.2.2.b, c and d do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

a) No penalty will be assessed if the applicable external interface is fully loaded in the import direction ~~and the energy from an External Transaction that would otherwise be requested cannot flow~~. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Demand Resource shall be calculated by subtracting the Demand Resource's Capacity Supply Obligation for the month from the Demand Resource's monthly Capacity Value. If a Demand Resource's Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31, of the year preceding the Capacity Commitment Period applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a positive value, the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month.

III.13.7.2.7.5.4. Determination of Net Payment.

If the sum of the Demand Resource Performance Penalties in a month is less than the sum of the Demand Resource Performance Incentives in the same month, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month can not exceed the total amount of the Demand Resource Performance Penalties in the same month.

The total of the Demand Resource Performance Incentives in a month can not exceed the total of the Demand Resource Performance Penalties in the same month. If the total Demand Resource Performance Penalties in a month exceeds the total Demand Resource Performance Incentives in the same month, the difference shall not be collected from load serving entities (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section 13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone, plus the sum of reconfiguration auction payments to those resources in the zone that were purchased by the ISO either to support an increase in the Installed Capacity Requirement (net of HQICCs), to meet requirements deferred from the Forward Capacity Auction to the reconfiguration auction, or to replace resources previously selected where the cost of such replacement is assigned to load serving entities in this Section III.13.2.5.2.5, less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (except those for resources clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.3.1. Calculation of Capacity Requirement and Capacity Load Obligation.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to

Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capability Year to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the 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 prior to the start of the 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 prior to the start of the 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 five FCA delivery periods for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.
The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.
The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.
Revenues collected from load serving entities in excess of revenues paid 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 minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the total Capacity Supply Obligations obtained in the exporting Capacity Zone and the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone's portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(c) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine Export Interface for as long as Casco Bay continues to pay to support the transmission upgrades. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.
The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.3.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

~~III.14 Intra-hour Transaction Scheduling Pilot Program~~

~~**III.14.1 Intra-hour Transaction Scheduling.**~~

~~In order to optimize the use of transmission ties between New York and New England, the ISO and New York ISO ("NYISO") are investigating alternatives to facilitate the exchange of energy between the New York Control Area and the New England Control Area. The alternatives being considered are revisions to processes and procedures that would facilitate transactions between participants and/or facilitate transactions between the ISOs based upon price differentials. The goal of this effort is to improve efficiency between both markets.~~

~~**III.14.2 Pilot Program.**~~

~~The ISO and NYISO have developed an initial pilot program (the "Pilot") to study the operational impacts of the implementation of intra-hour exchanges of energy based upon price differentials.~~

~~**III.14.3 Pilot Objectives.**~~

~~The objectives of the Pilot are as follows:~~

- ~~To identify operations issues associated with intra-hour short term exchanges of energy between Control Areas;~~
- ~~To evaluate tools and data needed to support intra-hour short-term exchanges of energy;~~
- ~~To observe the effects of intra-hour exchanges of energy on proxy bus prices;~~
- ~~To limit undesirable effects on normal system and market operations; and~~
- ~~To gather other information that may be useful in the development of a permanent mechanism or an alternative program.~~

~~**III.14.4 Notice.**~~

~~The ISO shall notify Participants fourteen (14) days in advance of the commencement of the Pilot via a "Special Notice" posted on the ISO's website.~~

~~**III.14.5 Implementation.**~~

~~The Pilot shall be implemented by the ISO in accordance with the Intra-hour Transaction Scheduling Pilot Program Description posted on the ISO's website.~~

~~**III.14.6 Settlement of Pilot Transactions.**~~

~~The aggregate net hourly charges or credits attributable to the purchase or sale of energy pursuant to this Section III.12 shall be segregated as an ISO market development expense and amortized broadly by the ISO over a three year period~~

~~**III.14.7 Effectiveness.**~~

~~This Section III.14 will be effective from the Operations Date through April 30, 2005.~~

SECTION II
MARKET RULE 1

APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. Overview.

Accounting for the provision of Operating Reserve and Replacement Reserve is performed on a daily basis. A generating Resource of a Market Participant that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Day-Ahead Energy Market subject to limitations when the Supply Offer includes Self-Scheduled hours as discussed in Section III.F.1.1.1. A generating Resource of a Market Participant, including a Local Second Contingency Protection Resource, that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Real-Time Energy Market provided that the Resource satisfies the criteria specified in Sections III.F.1.1.2 and III.F.2.1.7 below.

NCPC Credits are also provided for dispatchable External Transactions (both purchases and sales)~~,~~(excluding Coordinated External Transactions) for Increment Offers and Decrement Bids at External Nodes, for generating units operating as Synchronous Condensers at the direction of the ISO, for Dispatchable Asset Related Demand Resources (pumps only) that are not Self-Scheduled, for cancellation of generating Resources that are Pool-Scheduled Resources and for generating units backed down for the purposes of providing Operating Reserve or VAR support.

NCPC calculations shall be performed separately for the Day-Ahead and Real-Time Energy Markets.

III.F.1.1. Effect of Self-Schedules on NCPC Credits

III.F.1.1.1 Ineligibility for NCPC Credits (Day-Ahead Energy Market).

In the Day-Ahead Energy Market, the Resource's Self-Scheduled hours shall be the Self-Scheduled hours submitted in the Supply Offer.

(a) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation, a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains two blocks of contiguous Self-Scheduled hours separated by less than the Resource's minimum down time. For purposes of this calculation, a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days, or crosses the boundary between two Operating Days as described in (a) above, and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of non Self-Scheduled hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

III.F.1.1.2 Ineligibility for NCPC Credits (Real-Time Energy Market).

In the Real-Time Energy Market, the Self-Scheduled hours for the purpose of determining NCPC Credit eligibility shall be the Self-Scheduled hours from the Day-Ahead Schedule as modified in the Re-Offer electronic bidding (the Real-Time schedule as of 18:00 hours of the day prior to the Operating Day), including any redeclaration of Self-Scheduled hours by a Market Participant pursuant to Section 8 of ISO New England Manual-11.

(a) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if its Supply Offer (submitted either in the Day-Ahead Energy Market or during the Re-Offer Period) contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if it submits (as a Supply Offer in the Day-Ahead Energy Market or during the Re-Offer Period) two Self-Schedules separated by less than the Resource's minimum down time. For purposes of this calculation a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first Operating Day as meeting the minimum down time requirement but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days or crosses the boundary between two Operating Days and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

(e) For purposes of the above determinations, the minimum run time portion of a Real-Time Commitment Period commences with the first hour of the Real-Time Commitment Period in which the actual metered output of the generating Resource equals or exceeds 75 percent of the generating Resource's Economic Minimum Limit; provided that, if the Resource is a Fast Start Generator that never reaches 75 percent of its Economic Minimum Limit during its Real-Time Commitment Period, its minimum run time will commence with the first hour in which it has positive output. Each Real-Time Commitment Period is evaluated separately for the purpose of determining NCPC Credit eligibility.

The Real-Time NCPC Credit eligibility criteria set forth in subsections (a) through (e), above, shall be waived for additional hours of operation that result from an ISO request for extension of the Resource's operating schedule.

III.F.2. NCPC Credits.

NCPC Credits are calculated for each of the following situations:

(1) Pool-Scheduled Resources (Generators), including Local Second Contingency Protection Resources (Generators) and External Transactions (Day-Ahead and Real-Time Energy Markets), other than Coordinated External Transactions; Increment Offers and Decrement Bids cleared at External Nodes.

(2) Pool-Scheduled Resources (Synchronous Condensers and Special Constraint Resources ("SCR") - Real-Time Energy Market)

(3) Canceled Pool-Scheduled Resources (Real-Time Energy Market)

(4) Resources postured for reliability purposes (Real-Time Energy Market)

(5) Dispatchable Asset Related Demand Resources (pumps only) that are postured for reliability purposes in Real-Time.

(6) Self-Scheduled generating Resources providing Operating Reserves by operating in accordance with Dispatch Instructions in non-Self-Scheduled hours or at levels above the Self-Scheduled MW in Self-Scheduled hours during an Operating Day in which they have offered a contiguous block of Self-Scheduled hours, which meet the criteria for such Self-Schedules set forth in Section III.F.1, at least equal to their minimum run times.

III.F.2.1. Credits for Generating Resources.

For each Operating Day, the ISO calculates the NCPC Credit due each Market Participant for generating Resources.

In the Day-Ahead Energy Market, eligible generating Resources shall receive Day-Ahead NCPC Credits for all hours that are not Self-Scheduled. Except as otherwise provided in this Appendix F, all eligible generating Resources are eligible except generating Resources that have Self-Scheduled hours that do not meet the criteria set forth in Section III.F.1.1.1 are ineligible for Day-Ahead NCPC Credit. For purposes of the Day-Ahead NCPC Credit calculations, the Self-Scheduled hours shall be the Self-Scheduled hours in the Participant's Supply Offer.

In the Real-Time Energy Market, an eligible generating Resource is eligible to receive Real-Time NCPC Credits for all hours that are not Self-Scheduled and for MW amounts in excess of the Self-Scheduled MW for Self-Scheduled hours when the Resource operates above the Self-Scheduled MWs at the ISO's request. A generating Resource is not eligible to receive Real-Time NCPC Credits for any hour in which the Resource is ramping up from an off-line state prior to being released for dispatch, or ramping down after receiving a shutdown order. Self-Scheduled hours include hours when the Resource is ramping up to a Self-Scheduled hour from an off-line state, or down from a Self-Scheduled hour to an offline state and hours when the Resource is Self-Scheduled for Regulation. Eligible generating Resources shall consist of Pool-Scheduled Resources and Self-Scheduled Resources that meet the criteria in Section III.F.1.1.2 and any generating Resources specifically made eligible for Real-Time NCPC Credits in other Sections of this Market Rule 1.

III.F.2.1.1 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

III.F.2.1.2 Hourly Day-Ahead Offer Amount.

The ISO calculates the generating Resource's hourly Day-Ahead offer amount based on its Day-Ahead Offer Data that was utilized by the ISO in making the initial commitment decision and the generating Resource's cleared Day-Ahead MWh for that hour.

For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

(a) The ISO accounting process applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Resource Offer Data and if the Start-Up Fee is applicable for the MWh and status of the Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource Day-Ahead and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant. The Start-Up Fee will be associated with the first hour of the Resource's minimum run time on the day for which the Resource is committed. The Start-Up Fee will always be on the same Operating Day for both the Day-Ahead and Real-Time Energy Markets for purposes of calculating Real-Time NCPC Charges/Credits.

(b) Day-Ahead NCPC Credit calculations reflect the Start-Up Fee for the appropriate hot, intermediate, or cold state of the generating unit as it was scheduled in the Day-Ahead Energy Market.

III.F.2.1.3 Hourly Day-Ahead Value.

The ISO *calculates* the generating Resource's hourly Day-Ahead value as: generating Resource cleared Day-Ahead MWh * Day-Ahead LMP

III.F.2.1.4 Daily Day-Ahead Credit.

The ISO calculates the daily Day-Ahead credit for each generating Resource as follows:

(a) Sum hourly Day-Ahead offer amounts, including applicable No-Load Fees and Start-Up Fees, for the day.

(b) Sum hourly Day-Ahead values for the day.

(c) Day-Ahead credit equals any portion of the generating Resource's total Day-Ahead offer amount in excess of its total Day-Ahead value.

III.F.2.1.5 Day-Ahead Credit Allocation.

The ISO allocates the Day-Ahead credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource was scheduled and was eligible for NCPC Credit pro-rata based on Day-Ahead Load Obligations as follows:

Hourly Credit = Daily Credit * (Day-Ahead Load Obligations in scheduled hour) / (Total Day-Ahead Load Obligations in all scheduled hours))

[Note: Each credit is allocated back retaining its flag (Local Second Contingency Protection Resource, VAR etc.)]

III.F.2.1.6 Day-Ahead NCPC Credit: Hourly Market Participant Credit; Operating Day Total.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credit and the total Day-Ahead NCPC Credit for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset.

(b) For each scheduled hour, if the generating Resource is flagged specifically for the provision of VAR or voltage support, the Market Participant's share of Day-Ahead VAR credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits for all generating Resources for that Operating Day.

(c) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead VAR credits is equal to

50% of the Day-Ahead credit in that hour multiplied by the Market Participant’s Ownership Share in the Generator Asset and the Market Participant’s share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Day-Ahead credit in that hour multiplied by the Market Participant’s Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits and all Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day.

(d) For each scheduled hour, if the generating Resource is not flagged as a Local Contingency Protection Resource or VAR, the Market Participant’s share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant’s Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.7 Real-Time NCPC Credit Eligibility.

The ISO determines eligibility for Real-Time NCPC Credits. The following operating guidelines are used in the determination of Real-Time NCPC Credit eligibility:

(a) Generating Resources must be following Dispatch Instructions. For any hour that the generating Resource is not following Dispatch Instructions and the difference between the generating Resource’s energy value, in dollars, and energy offer amount, in dollars, (in this case, energy offer amount includes No-Load Fee and incremental energy price and does not include any Start-Up Fee) in that hour is negative, the generating Resource’s energy offer amount, in dollars, and energy value, in dollars, in that hour is excluded from the Real-Time NCPC Credit calculations.

(b) Generating Resources that trip during their Real-Time Commitment Periods are treated as set forth below:

(i) If the generating Resource trips during its minimum run time period and the generating Resource is otherwise eligible to receive Real-Time NCPC Credit, the Resource will be eligible for Real-Time NCPC Credit for the period beginning with the start of the Real-Time Commitment Period and ending at the time of the trip. For purposes of determining such generating Resource’s eligibility for Real-Time NCPC Credit, such generating Resource shall be eligible to recover a portion of its Start-Up Fee equal to the applicable Start-Up Fee multiplied by the quotient (not to exceed 1) of the generating Resource’s hours of operation during the current Real-Time Commitment Period and the generating Resource's minimum run time (Start-Up Fee* (Hours of operation/minimum run time)).

(ii) If the generating Resource trips after its minimum run time has been satisfied and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource will be eligible to receive Real-Time NCPC Credit for hours that were not Self-Scheduled during that Real-Time Commitment Period.

(iii) If the generating Resource trips, is requested to restart by the ISO, and returns to operate as requested, and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource is eligible to receive Real-Time NCPC Credits (including Start-Up Fee, No-Load Fee and incremental Energy price) for the new Real-Time Commitment Period.

(iv) Generating Resources that trip and return to operate that are not requested to restart by the ISO are treated as Self-Scheduled Resources and are not eligible for Real-Time NCPC Credits (Start-Up Fees and No Load Fee) for the new Real-Time Commitment Period.

When a generating Resource trips off line as the result of an equipment failure that involves equipment located on the electric network beyond the low voltage terminals of the generating unit step-up transformer, the ISO shall not treat the event as a trip for the purposes of determining the generating Resource's eligibility for Real-Time NCPC Credit for that Real-Time Commitment Period. It is the responsibility of the Lead Market Participant for the generating Resource to inform the ISO at xtrip@iso-ne.com within thirty (30) days that the trip was the result of such a transmission-related event.

(c) If a generating Pool-Scheduled Resource is otherwise eligible to receive Real-Time NCPC Credit and waives its minimum run time at the ISO's request, or if the ISO accepts an offer from a generating Pool-Scheduled Resource that is otherwise eligible to receive Real-Time NCPC Credit to waive its minimum run time and the ISO agrees to allow the Resource to shut down prior to completion of the generating Pool-Scheduled Resource's minimum run time:

(i) The generating Pool-Scheduled Resource shall be considered to have completed its minimum run time in calculating Real-Time NCPC Credits for which the generating Pool-Scheduled Resource is otherwise eligible; and

(ii) The generating Pool-Scheduled Resource's applicable Start-Up Fee shall be included in the calculation of said NCPC Credits.

III.F.2.1.8 Hourly Real-Time MWh.

The ISO determines the generating Resource's hourly Real-Time MWh based on the values submitted to the ISO by the Assigned Meter Reader for that hour.

III.F.2.1.9 Hourly Real-Time Energy Offer Amount.

The ISO calculates the generating Resource's hourly Real-Time energy offer amount based on its prices contained in the Supply Offer (if said Supply Offer has been mitigated, the mitigated Supply Offer shall be used for this calculation) for all eligible hours. For pool-scheduled hours, the Supply Offer price is multiplied by the lesser of the generating Resource's Desired Dispatch Point (provided that any Desired Dispatch Point below the Resource's Economic Minimum Limit will be deemed equal to the Economic Minimum Limit) or its actual metered output for that hour less the Resource's cleared Day-Ahead MWh. For generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours, the Supply Offer price (excluding the Start-Up Fees and No-Load Fee) is multiplied by the lesser of the DDP or actual metered quantity less the greater of the Resource's Self-Scheduled MW or the Resource's cleared Day-Ahead MWh. Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the output of the unit that is attributable to its submittal of a Self-Schedule for Regulation. For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

III.F.2.1.10 Application of Start-Up Fee and Hourly No-Load Fee.

The ISO applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Generator Offer Data and if the Start-Up Fee is applicable for the MWh and status of the generating Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource in Real-Time and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant or if that Participant's Resource was scheduled in the Day-Ahead Energy Market. The No-Load Fee is not applicable in any hour if the total number of hours that the Resource cleared in the Day-Ahead Energy Market is greater than the total number of hours that the Resource had actual generation greater than zero.

If the total number of hours that the Resource had actual generation greater than zero is greater than the total number of hours that the Resource cleared in the Day-Ahead Energy Market, the No-Load Fees would be applicable once the total number of hours that the Resource actually ran in Real-Time exceeded the total number of hours that the Resource cleared in the Day-Ahead Energy Market.

III.F.2.1.11

If applicable, when a generating Resource is started during the day at the direction of the ISO, the generating Resource's Real-Time offer amount calculated for that day includes its Start-Up Fee based on the appropriate hot, intermediate, or cold state of the generating Resource. For generating Resources that start generating for the ISO from a condensing state, the applicable Start-Up Fee for that generating Resource shall be the Start-Up Fee submitted that is associated with the hot state of the unit.

III.F.2.1.12

If applicable, the generating Resource's Real-Time calculated offer amount includes its hourly No-Load Fee prorated for all hours of operation as follows, using a 10% tolerance:

> If: lesser of (Real-Time MWh or Desired MW) < .9 * (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time),
> Then: hourly No-Load Fee is prorated by (lesser of (Real-Time MWh or Desired MW) / (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time).

III.F.2.1.13 Generating Resource Hourly Real-Time Value.

The ISO calculates the generating Resource's hourly Real-Time value for all eligible hours as:

> ((generating Resource metered value – max (generating Resource cleared Day-Ahead MWh, generating Resource Real-Time Self-Schedule MWh)) * (Real-Time LMP at generating Resource Node)) + generating Resource Regulation Opportunity Cost.

III.F.2.1.14 Generating Resource Daily Real-Time Credits.

The ISO calculates the daily Real-Time credits for each generating Resource as follows:

(a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day.

(b) Sum hourly Real-Time values for the day.

(c) Real-Time credits are equal to any portion of the generating Resource's total Real-Time offer amount in excess of its total Real-Time value.

III.F.2.1.15 Real-Time Credit Allocation.
The ISO allocates the Real-Time credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource actually operated and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * (Real-Time Load Obligation in operating hour) / Total Real-Time Load Obligations in all operating hours)

III.F.2.1.16 Real-Time NCPC Credits; Hourly Market Participant Credit; Operating Day Total.
The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as providing Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time SCR NCPC Credits for all generating Resources for that Operating Day,

(b) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(c) For each scheduled hour, if the generating Resource is flagged as a VAR Generator, the Market Participant's share of Real-Time VAR credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits for all generating Resources for that Operating Day,

(d) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time VAR credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits and all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(e) For each scheduled hour, if the generating Resource is not flagged as a Local Second Contingency Protection Resource or VAR, the Market Participant's share of Real-Time economic NCPC Credit is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.17 Addition of Hourly Shortfall Payments.

Generating Resources that are Pool-Scheduled Resources in the Day-Ahead Energy Market that are available, can deliver Energy and are not Postured, but are not economically dispatched in Real-Time and have not changed their incremental energy offers during the re-offer period, are eligible to receive the difference between the Real-Time and Day-Ahead LMP at the generator bus times the Day-Ahead scheduled MWh for hours when the Real-Time LMP is greater than the Day-Ahead LMP. Any payments made for each hourly shortfall are added to the total Real-Time economic NCPC Credits, Real-Time Local Second Contingency Protection Resource NCPC Credits or Real-Time VAR credits, as applicable, for the applicable Operating Day.

III.F.2.1.18 Addition of Minimum Generation Emergency Credits.

When a Minimum Generation Emergency has been declared (see Section 2.5.13.2 of ISO New England Manual M-11), generating Resources that are otherwise eligible to receive Real-Time NCPC Credits may be eligible to receive Minimum Generation Emergency Credits as provided below:

(a) Minimum Generation Emergency Credits will only be available in the Data Reconciliation Resettlement of the monthly services customer bill for the Operating Day(s) in which the Minimum Generation Emergency was declared.

(b) Minimum Generation Emergency Credits must be requested by sending a letter to the ISO's Market Support Services Department (custserv@iso-ne.com) within 20 business days after issuance of the monthly services customer bill that covers the hours of Minimum Generation Emergency for which a claim is being made. Requests received later than 20 business days after the issuance of the monthly services customer bill that includes the Minimum Generation Emergency hours for which a claim is being made will not be accepted.

(c) The lesser of the generating Resource's Desired Dispatch Point or actual metered output must be above the generating Resource's Economic Minimum Limit for each hour for which Minimum Generation Emergency Credit is requested.

(d) The Minimum Generation Emergency Credit for each eligible hour will be calculated as follows:

(i) The generating Resource's Economic Minimum Limit will be subtracted from the lesser of the generating Resource's Desired Dispatch Point ("DDP") or Real-Time Generation Obligation. Generating Resources with DDPs above Economic Minimum Limits because they are ramp rate constrained when being dispatched down to their Emergency Minimum Limits will have the result of the above calculation set to zero.

(ii) The result of step (i) will be multiplied by the Supply Offer price (in this case excluding the daily Start-Up Fee but not the hourly No-Load Fee) associated with the appropriate Supply Offer Energy block

(iii) The result of step (ii) will be reduced by any revenue received during that hour in the Real-Time Energy Market due to a non-zero LMP for the hour(s) for which the Minimum Generation Emergency was declared.

(e) Resources receiving Minimum Generation Emergency Credits under this Section III.F.2.1.18 shall be ineligible to receive Real-Time NCPC Credit for the same hour(s).
Charges associated with Minimum Generation Emergency Credits are discussed in Section 3 of this Appendix F.

III.F.2.2. Real-Time Credits for Pool-Scheduled Synchronous Condensers.

For each Operating Day, the ISO calculates the NCPC Credits due each Market Participant for Pool-Scheduled Resources scheduled as Synchronous Condensers.

III.F.2.2.1 Information Retrieved.

The ISO retrieves the following information:

(a) Dispatcher generation scheduling and operations logs

(b) Generator Offer Data

III.F.2.2.2 Duration of Pool-scheduled Periods of Synchronous Condensing Operations.

The ISO calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.

III.F.2.2.3 Condensing Offer Amount.

The ISO calculates each generating Resource's condensing offer amount for each period by multiplying the duration (in hours) by the hourly price to condense as specified in the Offer Data. If no hourly price to condense is listed in the Generator Offer Data, an hourly price of zero will be assumed and no payment will be made.

III.F.2.2.4 Condensing Credit.

When a generating Resource is requested to start condensing from an off-line state, a condensing credit is provided equal to the Resource's condensing Start-Up Fee as specified in the Offer Data.

III.F.2.2.5 VAR Credit.

If a unit is flagged as a VAR Resource and as a Synchronous Condenser, it will be compensated by a VAR credit.

III.F.2.2.6 Market Participant's Real-Time NCPC Condensing Credits.

The ISO calculates the daily Real-Time NCPC condensing credits for each Market Participant by summing all remaining hourly condensing generating Resource offer amounts, including applicable Start-Up Fees, for the Operating Day taking the Market Participant's Ownership Share into account.

III.F.2.2.7 Total Real-Time NCPC Condensing Credits.

The ISO sums the Real-Time NCPC condensing credits for all Market Participants for each Operating Day.

III.F.2.3. Credits for Pool-Scheduled External Transaction Purchases or Increment Offers at External Nodes.

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction purchases (modeled as Supply Offers at External Nodes) or Increment Offers at External Nodes as follows. These calculations only apply to External Transaction purchases submitted that are dispatchable and are submitted as source equals sink, or cleared Increment Offers at External Nodes. Notwithstanding anything to the contrary in this Section III.F.2.3, Market Participants shall not be eligible to receive Real-Time NCPC Credits or Day-Ahead NCPC Credits for Coordinated External Transaction purchases.

III.F.2.3.1

Real-Time NCPC eligibility for pool-scheduled External Transactions Purchases (priced imports).

(a) For each hour that a pool-scheduled External Transaction purchase is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions purchases are only eligible for Real-Time NCPC Credits to the extent that the Real-Time transaction (measured in MWh) exceeds the associated Day-Ahead schedule.

III.F.2.3.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction purchases, and Increment Offers at External Nodes

(c) hourly pool-scheduled Day-Ahead and Real-Time External Transaction purchase offer price curve ($/MWh, MW), and hourly Increment Offer price curve ($/MWh,MW) submitted at External Nodes

(d) Day-Ahead and Real-Time LMPs

(e) Transaction flags (Local Second Contingency Protection Resource)

III.F.2.3.3 Day-Ahead Offer Amount.

The ISO calculates the hourly Day-Ahead offer amount for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the transaction offer price.

III.F.2.3.4 Hourly Day-Ahead Value.

The ISO calculates the hourly Day-Ahead value for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the Day-Ahead LMP at the applicable External Node.

III.F.2.3.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction purchase or Increment Offer at an External Node as follows:

(a) Day-Ahead offer amounts for the hour

(b) Day-Ahead values for the hour

(c) Day-Ahead NCPC Credits for External Transaction purchases or Increment Offers equal any portion of the import transaction’s hourly Day-Ahead offer amount in excess of its hourly Day-Ahead value; provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction purchases or Increment Offers for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction sales or Decrement Bids for the External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the total External Transaction purchases or Increment Offers at the External Node are not offset by those of the total cleared External Transaction sales or Decrement Bids. The External Transaction purchases megawatts will be offset in order from highest to lowest price.

III.F.2.3.6 [Reserved.]

III.F.2.3.7 Day-Ahead NCPC Credits: Market Participant's Hourly Credits.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credits as follows:
For each scheduled hour, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour.

III.F.2.3.8 Hourly Real-Time Offer Amount.

The ISO calculates the hourly Real-Time offer amount for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead schedule by the transaction offer price.

III.F.2.3.9 Hourly Real-Time Value.

The ISO calculates the hourly Real-Time value for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead transaction MWh amount by the Real-Time LMP of the applicable External Node.

III.F.2.3.10 Real-Time Credits Calculation.

The ISO calculates the daily Real-Time credits for Real-Time External Transaction purchases as follows:

(a) Sum hourly Real-Time offer amounts for the day

(b) Sum hourly Real-Time values for the day

(c) Real-Time daily credit equals the portion of the External Transaction purchase's total daily Real-Time offer amount in excess of its daily Real-Time value.

III.F.2.3.11 Real-Time Credits Allocation.

The ISO allocates the Real-Time credits, for each External Transaction purchase for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.3.12 Real-Time NCPC Credits: Market Participant's Hourly and Operating Day Total. The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the External Transaction purchase is flagged as Local Second Contingency Protection Resource, the Market Participant's share of Local Second Contingency Protection Resource economic NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all External Transaction purchases for that Operating Day,

(b) For each scheduled hour, if the External Transaction purchase is not flagged as Local Second Contingency Protection Resource, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time NCPC Credits for all External Transaction purchases for that Operating Day.

III.F.2.4. Credits for Pool-Scheduled External Transactions Sales or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (Pumps Only). For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction sales (modeled as Demand Bids at External Nodes) or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (pumps only) as follows. Credits for pool-scheduled External Transaction sales or Decrement Bids at External Nodes only apply to External Transaction sales submitted that are Dispatchable and are submitted as source equals sink, or cleared Decrement Bids at External Nodes. Notwithstanding anything to the contrary in this Section III.F.2.4, Market Participants shall not be eligible to receive Real-Time NCPC Credits and Day-Ahead NCPC Credits for Coordinated External Transaction sales. Dispatchable Asset Related Demand Resources (pumps only) are eligible for NCPC Credits in hours for which they are not Self-Scheduled and are following Dispatch Instructions. Dispatchable Asset Related Demand Resources (pumps only) that are Self-Scheduled for any portion of an hour shall be considered Self-Scheduled for the entire hour and shall not be eligible for NCPC Credits in that hour.

III.F.2.4.1

Real-Time NCPC Credit eligibility for pool-scheduled External Transactions Sales (priced exports) is determined as follows:

(a) For each hour that a pool-scheduled External Transaction sale is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions sales are only eligible for Real-Time NCPC to the extent that the Real-Time transaction (measured in MWh) is scheduled to consume more than the associated Day-Ahead schedule.

III.F.2.4.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction sales (positive values), and Decrement Bids at External Nodes

(c) Pool-scheduled Day-Ahead scheduled consumption and Real-Time actual consumption for Dispatchable Asset Related Demand Resources (pumps only) (positive values)

(d) hourly pool-scheduled Day-Ahead and Real-Time External Transaction Demand Bid cost curve ($/MWh, MW), and hourly Decrement Bid cost curve ($/MWh,MW) submitted at External Nodes

(e) hourly pool-scheduled Real-Time Demand Bid cost curve ($/MWh, MW) for Dispatchable Asset Related Demand Resources (pumps only)

(f) Day-Ahead and Real-Time LMPs

III.F.2.4.3 Day-Ahead Bid Amount.

The ISO calculates the hourly Day-Ahead bid amount for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Demand Bid price.

III.F.2.4.4 Day-Ahead Cost.

The ISO calculates the hourly Day-Ahead cost for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Day-Ahead LMP at the applicable External Node.

III.F.2.4.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction sale or Decrement Bid at an External Node as follows:

(a) Day-Ahead bid amounts for the hour

(b) Day-Ahead costs for the hour

(c) Day-Ahead NCPC Credits for External Transaction sales or Decrement Bids equal any portion of the sale transaction's hourly Day-Ahead cost in excess of its hourly Day-Ahead bid amount provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction sales or Decrement Bids for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction purchases or Increment Offers for the same External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the External Transaction sales or Decrement Bids at the External Node are not offset by those of the total cleared External Transaction purchases or Increment Offers. The External Transaction sales megawatts will be offset in order from lowest to highest price.

III.F.2.4.6 [Reserved.]

III.F.2.4.7 Real-Time Bid Amount - External Transaction Sale.

The ISO calculates the hourly Real-Time bid amount for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the transaction Demand Bid price.

III.F.2.4.8 Real-Time Bid Amount - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time bid amount for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption less any cleared Day-Ahead consumption by the Dispatchable Asset Related Demand Resources (pumps only) Demand Bid price.

III.F.2.4.9 Real-Time Cost - External Transaction Sale.

The ISO calculates the hourly Real-Time cost for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the Real-Time LMP of the applicable External Node.

III.F.2.4.10 Real-Time Cost - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time cost for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption hourly deviations from the cleared Day-Ahead amount by the Real-Time LMP of the applicable Node.

III.F.2.4.11 Real-Time Credits - External Transaction Sale.

The ISO calculates the daily Real-Time NCPC Credits for Real-Time External Transaction sales as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals the portion of the External Transaction sale’s total daily Real-Time bid amount that is less than its daily Real-Time cost.

III.F.2.4.12 Real-Time Credits Allocation - External Transaction Sale.

The ISO allocates the Real-Time NCPC Credits, for each External Transaction sale for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.4.13 Real-Time Credits -Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the daily Real-Time NCPC Credits for Real-Time Dispatchable Asset Related Demand Resources (pumps only) as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals any portion of total daily Real-Time costs in excess of its total daily Real-Time bid amount of the Dispatchable Asset Related Demand Resource (pumps only).

III.F.2.4.14 Real-Time Credits Allocation -Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO allocates the Real-Time NCPC Credits, for each Dispatchable Asset Related Demand Resources (pumps only) for each Operating Day, back to each hour in the Operating Day in which the Dispatchable Asset Related Demand Resources (pumps only) was scheduled as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.5. Credits for Canceled Pool-Scheduled Resources (Generators).

For each Operating Day, the ISO calculates an NCPC Credit for the cancellation of a start-up prior to the assigned commitment time for any generating Pool-Scheduled Resource that:

(a) Was not scheduled by the ISO in the Day-Ahead Energy Market, and

(b) Was issued Dispatch Instructions to start-up in Real-Time. This cancellation credit is based on values submitted by Market Participants as part of the Resource's Offer Data. The following Offer Data parameters are utilized in the calculation: hot to cold time, hot to inter time, hot startup cost, inter startup cost, cold startup cost, hot notification time, inter notification time, and cold notification time.

III.F.2.5.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of canceled generating Resources (dispatcher log)

(b) Applicable generator Start-Up Fee (hot startup cost, inter startup cost or cold startup cost)

(c) Generator flags (Local Second Contingency Protection Resource, VAR, or SCR)

(d) generation data

III.F.2.5.2 Cancelled Start Credit Calculation.

The ISO credits each Market Participant for cancellation based on a pro-rata share of the applicable generating Resource's Start-Up Fee, and associated notification time parameter (hot, inter, or cold) utilized by the ISO in the original commitment decision. The credit for cancelled starts is calculated as follows:

Cancelled Start Credit = Applicable Generator Start-Up Fee * (1- ((Cancel Time) /(Notification Time))),

Where,

Applicable Generator Start-Up Fee	equals (i) Hot Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is less than the Hot to Inter Time; (ii) Inter Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Inter Time and less than the Hot to Cold Time; or (iii) Cold Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Cold Time,
Cancel Time	equals the difference, in hours, between the original ISO Commitment Order Time for the unit and the time at which the ISO cancelled the commitment of the unit. Cancel Time must be less than or equal to Notification Time, otherwise, the Cancelled Start Credit is set equal to zero,
ISO Commitment Order Time	equals the time at which the unit was originally requested to be synchronized to the New England Transmission system,
Notification Time	equals the applicable number of hours required to synchronize the unit to the system as submitted as part of the Generating Resource's Offer Data (Hot Notification Time, Intern Notification Time, or Cold Notification Time), and

Cancelled Start Credit is limited to be no greater than the applicable Start-Up Fee and notification time cannot be longer than 24 hours.

III.F.2.5.3 Real-Time NCPC Credit.

The Real-Time NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in Section III.F.2.5.2 above for all generating Pool-Scheduled Resources that were not originally flagged as a Local Second Contingency Protection Resource or VAR.

III.F.2.5.4 Local Second Contingency Protection Resource NCPC Credit.

The Real-Time Local Second Contingency Protection Resource NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.1.13 above for all generating Pool-Scheduled Resources that were originally flagged as Local Second Contingency Protection Resources.

III.F.2.5.5 VAR Credit.

The Real-Time VAR credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.5.2 above for all generating Pool-Scheduled Resources that were originally flagged as VAR.

III.F.2.5.6 Reserved.

III.F.2.5.7 SCR Credits.

The Real-Time SCR credits associated with generating units identified as SCR Resources are billed as provided for in Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.F.2.5.8 Example.

An example of the cancelled start calculation is as follows:

> Asset ID ABC was scheduled after the close of the Day-Ahead Energy Market to start at 6:00 am. ISO Cancelled the unit Start Time, in Real-Time, at 4:00 am. Cancel Time Column is calculated by subtracting Start time – Cancel time (6 – 4 = Cancel Time is 2)
> To determine the amount Cancelled Start we look at the Start-Up Fee and we multiply it by 1 minus Cancel Time divided by Time to Start.

III.F.2.6. Credits for Generating Resources and Dispatchable Asset Related Demand Resources (pumps only) Postured for Reliability.

The ISO credits Dispatchable Asset Related Demand Resources (pumps only) for responding to the ISO's request to increase consumption to a level above what would have been consumed during normal economic operation. The ISO credits Postured generating Resources, both pool-scheduled and Self-Scheduled, for responding to the ISO's request to reduce or suspend normal economic operation. A Resource shall be considered postured when it meets the conditions described in the definition of "Postured" in the Tariff. The ISO takes into account any generator Regulation credits associated with the postured generating Resource for the provision of Regulation while postured in calculating the posturing credits for generating Resources. For a Dispatchable Asset Related Demand Resource (pumps only) that is Postured, the posturing credits are calculated in accordance with Section III.F.2.4.

III.F.2.6.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)

(b) Generator Offer Data

(c) 5 minute generation data from EMS

(d) Real-Time LMP data

(e) Real-Time Generation Obligation

(f) Generator Regulation credits

III.F.2.6.2 Posturing Credit Calculation.

The ISO credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Daily Energy Restrictions.* For generating Resources without energy restrictions, the posturing credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – GRC

Where

PAG	equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;
AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
UB	equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
GRC	(Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Daily Energy Restrictions.* For generating Resources with energy restrictions, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the hour that posturing began and ending at the end of the calendar day,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP - UB) – GRC

Where:

PAG equals the estimated hourly generation had the generating Resource not responded to Dispatch orders to reduce or suspend operation. Estimated operation for generating Resources following the Day-Ahead schedule prior to the posturing event will be determined by the Day-Ahead schedule. From the start of the posturing event through the end of the calendar day, PAG is set to the

Day-Ahead schedule for as long as available energy would have supported the operation. For generating Resources responding to DDP's in Real-Time or operating under Real-Time Self-Schedule changes prior to the posturing event, PAG will be set assuming economic operation would have occurred during posturing and throughout the day for as long as the available energy would have supported the operation;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource;

UB equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4 of the ISO New England Manual for Market Rule 1 Accounting, M-28.

III.F.2.6.3 Real Time NCPC Credits.

The Real-Time NCPC Credits for posturing for the Operating Day are equal to the sum of the non-VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.4 Real Time VAR Credits.

The Real-Time VAR credits for posturing for the Operating Day are equal to the sum of the VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.3. Charges for NCPC

III.F.3.1. Allocation.

The sum of Day-Ahead NCPC Credits for the Day-Ahead Energy Market, excluding the Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes, is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time NCPC Credits (excluding Posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Asset Related Demand Resources that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Asset Related Demand Resources for the Operating Day that result from operation in accordance with the ISO

’s instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic Minimum Limit. Real Time NCPC Credits associated with the Posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit. Notwithstanding anything to the contrary in this Section III.F.3, Coordinated External Transactions shall be excluded from the Real-Time Energy Market NCPC Charge calculation and Day-Ahead Energy Market NCPC Charge calculation.

The sum of Day-Ahead Local Second Contingency Protection Resource NCPC Credits associated with generating Resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region in proportion to the daily sum of their Day-Ahead Load Obligations within each affected Reliability Region. The sum of Real-Time Local Second Contingency Protection Resource NCPC Credits associated with generating units identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region and, under certain circumstances, to any adjacent Control Area purchasing Emergency energy from the ISO. Charges are allocated in proportion to the daily sum of Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) Operation that is above its Minimum Consumption Limit) plus applicable Emergency energy sales within each affected Reliability Region.

The sum of Day-Ahead and Real-Time NCPC Credits paid to Market Participants associated with Resources other than SCRs (including Synchronous Condensers and Postured Resources) that have been identified by the ISO as being required to provide voltage support or VAR support are collected from Market Participants in accordance with Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Each Market Participant’s Minimum Generation Emergency Charge is calculated as follows:

(1) For each generating Resource of the Market Participant for which a Minimum Generation Emergency Credit is calculated, subtract the Resource’s Economic Minimum Limit from its Real-Time Generation Obligation and then multiply the result by the Market Participant’s Ownership Share in the

Resource. The sum of the results of such calculations shall be that Market Participant's Exempt Real-Time Generation Obligation.

(2) Subtract the sum of the Exempt Real-Time Generation Obligations for all Market Participants from the total Real-Time Generation Obligation of all Market Participants at Locations within the Reliability Region(s) for which a Minimum Generation Emergency was declared.

(3) Subtract the Market Participant's Exempt Real-Time Generation Obligation, as calculated in step (1) above, from its total Real-Time Generation Obligation within the Reliability Region(s) for which a Minimum Generation Emergency was declared, and then divide that result by the result in step (2).

(4) Multiply the total Minimum Generation Emergency Credit by the result in step (3). This result is the Market Participant's Minimum Generation Emergency Charge.

III.F.3.2. Calculations

III.F.3.2.1 Day-Ahead NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total Day-Ahead NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead NCPC Credits, as previously calculated, for generating Resources, Postured generators (non-VAR) and Dispatchable Asset Related Demand (pumps only).

III.F.3.2.2 Local Second Contingency Protection Resource NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participants' Day-Ahead Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.3 VAR related NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total VAR related NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead VAR credits.

III.F.3.2.4 NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the NCPC Charges for the Day-Ahead Energy Market by allocating the total economic NCPC cost for the Day-Ahead Energy Market to each Market Participant based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub). For each External Node, if there are any Day-Ahead External Transaction purchase credits for each External Transaction purchase or Increment Offer cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Load Obligations at the External Node. If there are any Day-Ahead External Transaction sale credits for each External Transaction sale or Decrement Bid cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Generation Obligations at the External Node.

III.F.3.2.5 Local Second Contingency Protection Resource NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Day-Ahead Energy Market for each affected Reliability Region by allocating the total Local Second Contingency Protection Resource NCPC cost for the Day-Ahead Energy Market for each affected Reliability Region to each Market Participant within each affected Reliability Region based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations within the affected Reliability Region (not including the Hub).

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Day-Ahead Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.F.3.2.6 VAR Charges, Day-Ahead Energy Market, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the VAR Charges for the Day-Ahead Energy Market by allocating the sum of the total VAR related NCPC cost for the Day-Ahead Energy Market to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.7 Non-Synchronous Condenser related Economic NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total non-Synchronous Condenser related economic NCPC cost associated with the Real-Time Energy Market by summing all Market Participant's Real-Time NCPC Credits not related to Synchronous Condensers, as previously calculated, and the total Synchronous Condenser related NCPC cost (non-VAR related) associated with the Real-Time Energy Market by summing all Market Participants' non-VAR related Real-Time Synchronous Condenser related NCPC Credits for generating Resources, pool scheduled External Transaction purchases, pool- scheduled External Transaction sales and Dispatchable Asset Related Demand Resources (pumps only), cancelled Pool-Scheduled Resources excluding Resources Postured for reliability.

III.F.3.2.8 Local Second Contingency Protection Resource NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total Local Second Contingency Protection Resource NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.9 SCR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total SCR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time SCR NCPC Credits.

III.F.3.2.10 VAR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total VAR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time VAR credits including VAR credits associated with Synchronous Condensers and Postured generating Resources.

III.F.3.2.11 [Reserved.]

III.F.3.2.12 Real-Time Load Obligation Deviation.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1) by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead -Load Obligation over all Locations (including the Hub).

III.F.3.2.13 [Reserved.]

III.F.3.2.14 Real-Time Generation Obligation Deviation at External Nodes.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Generation Obligation Deviation at External Nodes by summing the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

III.F.3.2.15 Other.

The ISO calculates for each Operating Day the non-Postured non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related, non-Regulation and non-SCR related economic NCPC Charges for the Real-Time Energy Market for each Market Participant by allocating the total Real-Time non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related and non-SCR related NCPC cost to each Market Participant based on their daily pro-rata share of the daily sum of the following hourly Real-Time deviations:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resources Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following ISO Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following ISO Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1)

[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation

Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.
[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

plus,

(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.2.16 Local Second Contingency Protection Resource NCPC Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Real-Time Energy Market for each Market Participant within each affected Reliability Region by allocating the total Real-Time Local Second Contingency Protection Resource NCPC cost to each Market Participant within each affected Reliability Region based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Real-Time Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(a) For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, for hours in which there is a Local Second Contingency Protection Resource NCPC cost (as calculated in Section III.F.3.2.8) and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of proportional shares of Real-Time Load Obligations as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The proportionate share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-37 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
1385 Cable External Node	Northport-Norwalk Harbor (1385 Line)	Connecticut	100% to Connecticut
Cross Sound Cable External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(b) For each month, the ISO performs an evaluation of total Real-Time Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph b, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only) above its Minimum Consumption Limit.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.3.2.17 VAR Charges, Real-Time Energy Market.
The ISO calculates for each Operating Day the VAR Charges (including Synchronous Condensers) associated with the Real-Time Energy Market by allocating the total Real-Time VAR cost to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.18 SCR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the SCR Charges associated with the Real-Time Energy Market by charging the total Real-Time SCR cost to the appropriate entities based on Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Accepted Electric Industry Practice, sometimes referred to as Good Utility Practice, means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric generation and transmission industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Accepted Electric Industry Practice is not limited to a single, optimum practice method or act to the exclusion of others, but rather is intended to include practices, methods, or acts generally accepted in the region.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Adjusted Regulation Obligation is equal to a Market Participant’s total Real-Time Load Obligation ratio share of the total amount of Regulation provided that hour, adjusted for any internal bilateral transactions for Regulation.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

Amount Interrupted is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of one or more individual end-use metered customers receiving service from the same point or points of electricity supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy reduction during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (v) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time Demand Resource Dispatch Hours within the same Operating Day in the month for that resource; or (iv) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision of Blackstart Service.

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for the day); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for the each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); and (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Clearing Price Floor is described in Section III.13.2.7.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Requirement is a load serving entity's initially allocated share of the Installed Capacity Requirement, prior to any Capacity Load Obligation Bilaterals, during a Capacity Commitment Period for a Capacity Zone, as described in Section III.13.7.3.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Carried Forward Excess Out-of-Market Capacity is calculated as described in Section III.13.2.7.8.2.1(c)(i) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for the other Covered Entities and for NEPOOL pursuant to the Participants Agreement.

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.9.5.3.

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.9.5.3.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each power year, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Generating Capacity Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the weekly billing process in any billing period.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area, for purposes of Section II of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Council; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area, for purposes of Section III of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (i) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s); (ii) maintain scheduled interchange with other Control Areas, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is determined in accordance with Section III.13.2.4 of Market Rule 1.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Critical Peak Demand Resource is a type of Demand Resource, and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce electrical usage during Demand Resource Critical Peak Hours or shift electrical usage from Demand Resource Critical Peak Hours to other hours and reduce the amount of capacity needed to deliver a comparable or acceptable level of service at those end-use customer facilities. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Customer Baseline is the average aggregate hourly load, rounded to the nearest kWh, for each of the 24 hours in a day for each Load Response Program Asset participating in the Real-Time Price Response Program, and the average aggregated five-minute load, rounded to the nearest kWh, for each of the 24 hours in a day for Real-Time Demand Response Assets and Real-Time Emergency Generation Resource assets.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Real-Time Demand Response Asset to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E.6.

Demand Reduction Value is the quantity of reduced demand, measured at the Retail Delivery Point for the end-use customer, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Critical Peak Hours means Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours.

Demand Resource Financial Assurance Requirement is an amount of financial assurance required from DRP-Only Customer registering a Demand Resource in the Day-Ahead Energy Market. This amount is calculated pursuant to Section VIII.A of the ISO New England Financial Assurance Policy.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January.

Demand Resource Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and the pumping load associated with pumped storage generators) for Monday through Friday on non-Demand Response holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8.

Demand Response Holiday is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member or DRP-Only Customer that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) is the Dispatch Rate expressed in megawatts.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource’s or contract’s Supply Offer or Demand Bid parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand dispatched by the ISO in accordance with the Offer Data.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability and must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions and must meet the technical requirements specified in the ISO New England Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point for the end-use customer, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Distributed Generation resources are not eligible for energy payments from ISO-administered energy markets. Generation resources cannot participate in the Forward Capacity Market as Demand Resources, unless they meet the definition of Distributed Generation.

DRP-Only Customer is a Market Participant that enrolls itself and/or one or more Demand Resources in the Load Response Program and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an ODR-Only Customer. References in this Tariff to a Non-Market Participant demand response provider or similar phrases shall be deemed references to a DRP-Only Customer.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of 0.8 times CONE or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency, for purposes of Section II of the Tariff, is an abnormal condition on the bulk power system(s) of New England and/or neighboring control areas that, if not immediately corrected, could lead to the shedding of firm electrical load. Such abnormal conditions are beyond the reasonable control and ability to avoid of the system operator of the region(s) experiencing such conditions. Such conditions could result from emergency outages of generating units, transmission lines or other equipment, or other such unforeseen circumstances such as load forecast errors.

Emergency, for purposes of Section III of the Tariff, is an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum generation amount, in MWs, that a generating unit can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted by certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

FCM Pivotal Supplier shall mean a Lead Market Participant whose total Qualified Capacity from its Existing Capacity Resources in a Capacity Zone minus the quantity of its capacity subject to Non-Price Retirement Requests in that Capacity Zone for the current Forward Capacity Auction is greater than the difference between the total MW from qualified Existing Capacity Resources in the Capacity Zone minus the sum of the quantity of capacity subject to Non-Price Retirement Requests in that Capacity Zone plus the Local Sourcing Requirement for that Capacity Zone.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the Retail Delivery Point for the end-use customer that can be produced by a Critical Peak Demand Resource, Real-Time Demand Response Resource, and Real-Time Emergency Generation Resource, in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets, 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.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a generator that has been registered in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the

Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation means the difference between the Average Hourly Output or Average Hourly Load Reduction of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

HQ Interconnection Excess is the difference between the HQ Interconnection transfer limit as determined by the ISO and the Commission approved MW value of Hydro Quebec Interconnection Capability Credits.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

Hydro Quebec Interconnection Capability Credits are credits that are granted to a Market Participant or group of Market Participants in accordance with the ISO New England System Rules, where the value of such credits is determined in accordance with the ISO New England Manuals.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer, a DRP-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Payment (ICAP Payment) means the monthly payments made to ICAP Resources for installed capacity during the ICAP Transition Period.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Installed Capacity Resource (ICAP Resource) means a resource that met the requirements to receive installed capacity payments during the ICAP Transition Period.

Installed Capacity Transition Period (ICAP Transition Period) is December 1, 2006 through May 31, 2010.

Insufficient Competition is defined in Section III.13.2.8.2 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures” or the “Small Generator Interconnection Procedures” pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer or DRP-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers or Demand Bids for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means generating resources that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region..

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the

Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer and/or a DRP-Only Customer and/or an ODR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset can deliver.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, measured at the retail delivery point of a Real-Time Demand Response Asset.

Measure Life is the estimated time a Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the Demand Reduction Value of the Demand Resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the Demand Reduction Value for an Existing Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1, which includes Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by a Demand Resource supplier as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by Demand Resource suppliers during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the data reconciliation process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource’s Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.4(c) of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource (including any payment as an ICAP Resource pursuant to the market rules in effect prior to December 1, 2006 or any ICAP Payment during the ICAP Transition Period pursuant to the market rules in effect from December 1, 2006 through May 31, 2010) and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New England Control Area, for purposes of Section II of the Tariff, is the Control Area (as defined in Section II.1.11) for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Control Area, for purposes of Section III of the Tariff, is the integrated electric power system to which a common automatic generation control scheme and various operating procedures are applied by or under the supervision of the ISO in order to: (i) match, at all times, the power output of the generators within the electric power system and capacity and energy purchased from entities outside the electric power system, with the load within the electric power system; (ii) maintain scheduled interchange with other interconnected systems, within the limits of Accepted Electric Industry Practice; (iii) maintain the frequency of the electric power system within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the NPCC and NERC; and (iv) provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice.

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.3.1.3.

Non-Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.B of that policy.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is calculated in accordance with Section VII.B.2(i) of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

ODR-Only Customer is a Market Participant that registers with the ISO an Other Demand Resource (as defined in Section III.1 of this Tariff) and that does not participate in other markets or programs of the New England Markets, provided, however, that a DRP-Only Customer may also be an FTR-Only Customer and/or an DRP-Only Customer.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

On-Peak Demand Resource is a type of Demand Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects 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 specified ODR performance hours of the ICAP Transition Period.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Out-of-Market Capacity is certain capacity that is counted in determining whether the Alternative Capacity Price Rule applies, as described in Section III.13.2.7.8 of Market Rule 1.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a generating unit asset or Load Asset, where such unit or load is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Payment is a sum of money due to a Covered Entity from the ISO, as remitting agent for the Covered Entities.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E.8.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that (i) reports the load as measured at the Retail Delivery Point, and, if there are other assets located behind the Retail Delivery Point, reports the output of one or more emergency generators as a single set of values, (ii) is assigned a unique asset identification number by the ISO, and (iii) participates in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response holidays in which the ISO dispatches Real-Time Emergency Generation Resources to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a Load Zone or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. Beginning on June 1, 2011, Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Accepted Electric Industry Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.
Real-Time Price Response Program is the program described in Appendix E to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the

New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Re-Offer Period is the period normally between 16:00 and 18:00 on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer, a DRP-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart O&M Payment is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

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STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: “Pre-scheduling” as specified in Section III.1.9, “Scheduling” as specified in III.1.10, and “Dispatch” as specified in III.1.11. This Market Rule 1 shall become effective on the Operations Date.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 [Reserved.]

III.1.5 [Reserved.]

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 [Reserved.]

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy bought and sold in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the procedures specified in this Market Rule 1 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 by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 [Reserved.]

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule to the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1.

Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, which ever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

A generating unit dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: 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 & ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline specified in the ISO New England Manuals and ISO New England Administrative Procedures and shall remain in effect without change throughout each such period for which a specification was submitted. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant’s Offer Data that does not conform to the Market Participant’s specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with notification time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units, as submitted in accordance with Section 1.10.1A(f), for such periods and the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and such Resources shall be treated as Pool-Scheduled Resources and shall be eligible to receive NCPC Credits under Section III.3.2.3 in accordance with the binding Supply Offers submitted.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be equal to or greater than zero and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External

Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the re-offer period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to $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 1. Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may be revised to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its minimum run time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's minimum run time; and

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed $100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) Each Market Participant owning or controlling the output of 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 superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits and Economic Minimum Limits are not used in determining the amount of energy (MW) in each marginal Supply Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits and Economic Minimum Limits.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids. Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, and the specified operating characteristics, offered by Market Participants to the ISO by the offer deadline specified in Section III.1.10.1A.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees and No-Load Fee, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1. Additionally, the Market Participant seller shall receive for Pool-Scheduled Resources scheduled in the Real-Time Energy Market that were not scheduled in the Day-Ahead Energy Market, a pro-rata share of its applicable Start-Up Fee if the ISO cancels its selection of the Resource as a Pool-Scheduled Resource and so notifies the Market Participant seller before the Resource is synchronized (“Cancellation Fee”).

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

(f) Eligibility for NCPC in the Day-Ahead Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(g) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by Resource Self-Schedules. The specific rules related to the impact of Resource Self-Schedules on eligibility for NCPC may be found in *Appendix F* of this Market Rule 1.

(h) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 may be affected by Resource trips. The specific rules related to the impact of Resource trips on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule 1.

(i) Eligibility for NCPC in the Real-Time Energy Market under Section III.3.2.3 is affected by ramping up in response to a start-up instruction and ramping down in response to a shutdown instruction. The specific rules related to the ramping impacts on eligibility for NCPC may be found in ***Appendix F*** of this Market Rule 1.

III.1.10.3 Self-Scheduled Resources.

Self-Scheduled Resources shall be governed by the following principles and procedures.

(a) [Reserved.]

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling any portion of that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;

(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by 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.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the re-offer period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by noon prior to the Operating Day for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the re-offer period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by noon prior to the Operating Day for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the re-offer period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) Day-Ahead NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.5.

(ii) Real-Time NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.2.16.

(iii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iv) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated External Transactions.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location and the Northport-Norwalk external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the period for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

$$b/a$$

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1..10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the “foregone” bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term “b.” The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the “foregone” bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term “a.”

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

$$b/a$$

If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.

The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 4:00 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource re-offer period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day or such other re-offer period as necessary to account for software failures or other events. During the re-offer period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) A Market Participant may adjust the schedule of a Resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the ISO is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect (or such shorter period, up to 20 minutes prior to the hour, when the ISO has notified the Market Participants that it has the necessary hardware, software, and procedures in place to implement the shorter notice period), as follows:

(i) A Market Participant may Self-Schedule any of its Resources consistent with the ISO New England Manuals and ISO New England Administrative Procedures;

(ii) [Reserved]; or

(iii) [Reserved]; or

(iv) A Market Participant may remove from service a Resource increment previously designated as Self-Scheduled consistent with the ISO New England Manuals and ISO New England Administrative Procedures.

(c) During the re-offer period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the re-offer period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the re-offer period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(d) **[Reserved.]**

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output.

The ISO shall have the authority to direct any Market Participant to adjust the output of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources, subject to an obligation to pay any applicable Start-Up Fees, No-Load Fee, or Cancellation Fees. The ISO shall adjust the output of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative

Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified. During each hour of any tests performed under Section III.1.11.3(c),(i), the Resources under test shall be considered Self-Scheduled Resources for the purposes of calculating NCPC Credits. Procedures related to the ISO's modification of operational related Offer Data and Market Participant requests for testing shall be as defined in the ISO New England Manuals.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to 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.1.11.5 Regulation.

(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service, by contractual arrangements with other Market Participants, or by purchases from the New England Markets at the rates set forth in Section III.3.2.2.

(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim Regulation Clearing Price is then calculated and the Regulation Rank Prices are updated using this interim Regulation Clearing Price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.

(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:

(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;

(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;

(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:

(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.

(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.

(iii) To more accurately estimate the actual Regulation Opportunity Cost that will be paid, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO’s website.

(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.

(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:

(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen); and

(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen), where,

LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit), And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.

(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.

For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.

(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial Regulation Clearing Price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial Regulation Clearing Price by substituting the initial Regulation Clearing Price for the generating

unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices that are greater than or equal to the initial Regulation Clearing Price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated Regulation Clearing Price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.

(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.

(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Accepted Electric Industry Practice.

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource submitted under Section III.1.10.7 and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase submitted under Section III.1.10.7 or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase submitted under Section III.1.10.7 satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

(e) Coordinated External Transactions are not evaluated for purposes of the calculations detailed in this Section III.2.4.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to zero for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to zero for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at $1,000/MWh;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to zero and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer’s knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

(i) local TMOR RCPF = $250/MWh;
(ii) system TMOR RCPF = $100/MWh;
(iii) system TMNSR RCPF = $850/MWh;
(iv) system TMSR RCPF = $50/MWh.

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for external interfaces for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented shall be 15 minutes, and the settlement interval for all other Locations shall be one hour.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the ISO Day-Ahead Energy Market. To accomplish this, the ISO will perform calculations to determine the following.

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location

(b) For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-

Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) For each Market Participant for each settlement interval, the ISO will determine the difference between the Day-Ahead Energy Market position (Section III.3.2.1(a)) and the Real-Time Energy Market position (Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each settlement interval, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price. The resulting excess or deficiency in Inadvertent Energy Revenue at each External Node shall then be summed to determine a single hourly value for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.2 Regulation.

(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly Regulation obligation through its own Resources or through an appropriate bilateral transaction, shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (j) of this Section. Notwithstanding the foregoing, the calculation of Regulation charges under this Section III.3.2.2 shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

(b) A Market Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for Time-On-Regulation Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Time-On-Regulation Megawatts, plus the unit-specific Regulation Opportunity Cost of the generating Resource supplying the Time-On-Regulation Megawatts, as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) A Market Participant supplying Regulation at the direction of the ISO shall receive a credit for Regulation Service Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Regulation Service Megawatts, multiplied by the Capacity-to-Service Ratio. The Capacity-to-Service Ratio is described under Subsection (h).

(d) Each Market Participant shall be charged its pro rata share of the total Regulation Service Credits for the hour, based upon the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour.

(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time-weighted average of all interval based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Section III.2.9A of this Market Rule 1.

(f) A Market Participant's Regulation Service Megawatts shall be determined by the ISO. A Market Participant's hourly Regulation Service Megawatts for each generating Resource providing Regulation shall be equal to the sum of the absolute value of the generation movement, in megawatts, towards the Regulation set point, such movement calculated in four second intervals based upon the generating Resource's Automatic Response Rate.

(g) A Market Participant's Time-on-Regulation Megawatts shall be determined by the ISO. A Market Participant's hourly Time-on-Regulation Megawatts for each generating Resource providing Regulation shall be equal to the Regulation capability provided multiplied by the minutes of Regulation provision in the hour, divided by sixty.

(h) The Capacity-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service Ratio may be changed from time to time and such changes shall be filed with the Commission for approval.

(i) In determining the credit under subsection (b) to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit-specific Regulation Opportunity Cost of a generating Resource shall be determined for each hour that the ISO requires a generating Resource to provide Regulation and shall be equal to the product of (i) the deviation of the generating Resource's output necessary to follow the ISO's Regulation signals from the generating Resource's expected output level if it had been dispatched in economic merit order multiplied by (ii) the absolute value of the difference between the Real-Time Price at the generation Node for the generating Resource and the megawatt weighted average Supply Offer price for the energy associated with the deviation of the generating Resource's expected output level if it had been dispatched in economic merit order.

(j) Amounts credited for Regulation Opportunity Cost in an hour shall be allocated and charged to each Market Participant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in MWhs during that hour.

III.3.2.3 NCPC Credits.

The following paragraphs describe the calculation of NCPC Credits and NCPC Charges. Additional information on these calculations may be found in Appendix F of this Market Rule 1.

(a) Except as otherwise provided for under Section III.3.2.3(f) and Section III.3.2.3(k), Market Participants' Pool-Scheduled Resources capable of providing Operating Reserve or Replacement Reserve shall be credited as specified below (an "NCPC Credit") based on the prices offered for the operation of such Resources, provided that the Resources were available for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for the Day-Ahead Energy Market:

(i) For each generating Pool-Scheduled Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start-Up Fees and No-Load Fee and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, if the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

(ii) Other Day-Ahead NCPC Credits shall be calculated as specified in Section III.F.2.

(c) Except as otherwise provided for under Section III.F.3, the sum of the foregoing credits calculated in accordance with Section III.3.2.3(b) shall be the "NCPC Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F. Notwithstanding anything to the contrary in this Section III.3.2.3, Coordinated External Transactions shall be excluded from the Day-Ahead Energy Market NCPC Charge calculation.

(e) At the end of each Operating Day, the following determinations shall be made:

(i) for each eligible hour for each synchronized Pool-Scheduled Resource of each Market Participant that operates as requested by the ISO and that is not committed for synchronized condensing: The total offered price, as calculated in accordance with Section III.F.2.1.9, shall be compared to the total value of that Resource's energy in the Real-Time Energy Market, as calculated in accordance with Section III.F.2.1.13. If the total offered price exceeds the total value, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(ii) For each synchronized Pool-Scheduled Resource or Self-Scheduled Dispatchable Asset Related Demand Resource of each Market Participant that is associated with pumping load and that operates as requested by the ISO in accordance with Section III.3.2.3(f): the total Real-Time costs of energy consumption, as calculated in accordance with Section III.F.2.4.10, shall be compared to the total bid amount of that Resource's energy consumption in the Real-Time Energy Market, as calculated in accordance with Section III.F.2.4.7. If the total Real-Time costs exceed the total bid amount, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(iii) For each pool-scheduled External Transaction sale of each Market Participant that operates as requested by the ISO: the difference between a Market Participant's Real-Time bid price and Real-Time costs as determined pursuant to Section III.F.2 shall be credited to the Market Participant as a Real-Time NCPC Credit.

For purposes of this Section, a Market Participant is deemed to operate as requested by the ISO if it follows dispatch instructions. A generator is considered to be following a dispatch instruction if the actual output of the generator is not greater than 10% above its desired dispatch point and is not less than 10% below its desired dispatch point for each interval in the hour. Generators with an Economic Max less than or equal to 50 MWs are considered to be following a dispatch instruction if the actual output of the generator is not greater than 5 MWs above its desired dispatch point and is not less than 5 MWs below its desired dispatch point for each interval in the hour. If the generator violates this criterion in any interval during the hour, the generator is considered to be not following dispatch instructions for the entire hour.

(f) A Market Participant's Pool-Scheduled Resource or Self-Scheduled generating Resource, the output of which is reduced or suspended at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve or for the provision of voltage support, shall be credited in an amount equal to the following:

For generating Resources, the credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG -AG) x (ULMP -UB) – RC where:

PAG equals the estimated hourly generation had the generator not responded to dispatch orders to reduce or suspend operation taking any limited energy restrictions into account, such estimated hourly generation to be determined in accordance with procedures defined in the ISO New England Manuals;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time Price associated with the generating Resource that is reduced or suspended for each hour;

UB equals the Supply Offer price associated with PAG for that generating Resource whose output is reduced or suspended;

RC equals any Regulation credits from Section III.3.2.2(i); and
where ULMP -UB shall not be negative and Posturing Credit shall not be negative.

The amount, in MW, of a Market Participant's pool-scheduled Dispatchable Asset Related Demand Resource or Self-Scheduled Dispatchable Asset Related Demand Resource that is associated with pumping load which is maintained out of economic merit at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve, shall be credited in accordance with Section III.3.2.3(b) and III.3.2.3(e).

(g) Except as otherwise provided for under Section III.F.3, the sum of the foregoing NCPC Credits, plus any Cancellation Fees paid in accordance with Section III.1.10.2(d), such Cancellation Fees to be applied to the Operating Day for which the unit was scheduled, shall be the non-synchronized condensing NCPC Charge for the Real-Time Energy Market in each Operating Day.

(h) The non-synchronized condensing and synchronized condensing NCPC Charge for the Real-Time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Notwithstanding the foregoing, Coordinated External Transactions shall be excluded from the Real-Time Energy Market NCPC Charge calculation. For the purposes of calculating generation deviations, if a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating Real-Time NCPC Charges. For the purposes of calculating Real-Time NCPC Charges, any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation.

(i) At the end of each Operating Day, Market Participants shall be credited on the basis of their offered prices for synchronized condensing for any hydropower or combustion turbine units operated as synchronous condensers but producing no energy.

(j) The sum of the foregoing NCPC Credits as specified in Section III.3.2.3(i) shall be the NCPC Charge for synchronized condensing in the Real-Time Energy Market for the Operating Day in the New England Control Area.

(k) Market Participants shall not be eligible to receive Day-Ahead NCPC Credits or Real-Time NCPC Credits for Coordinated External Transactions.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with

Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs attributable to the purchase of Emergency energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396) tie line and Orrington-Lepreau (390) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 of this Market Rule 1, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter

Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.5 Transmission Congestion Revenue & Credits Calculation

III.5.1 Non-Market Participant Transmission Congestion Cost Calculation.

III.5.1.1 Calculation by ISO.

When the transmission system is operating under constrained conditions, the ISO shall calculate Congestion Costs.

III.5.1.2 General.

The basis for the Congestion Costs shall be the differences in the Congestion Component of the Locational Marginal Prices between points of delivery and points of receipt, as determined in accordance with Section III.2 of this Market Rule 1.

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation.

Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Congestion Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using TOUT Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility.

Except as provided in Section III.A.8.4 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the FTRs held at the time of the constrained hour.

(b) FTRs shall be awarded to winning bidders in the FTR Auctions pursuant to Section III.7.

(i) An entity that acquires an FTR through the FTR Auction shall automatically be recognized by the ISO as the registered FTR Holder of that FTR, subject to having already met the eligibility criteria for bidding in the FTR Auction. The registered FTR Holder shall be entitled to receive or be obligated to make FTR payments arising from such FTR in accordance with Section III.5.2.

(ii) An entity that acquires an FTR through the FTR Auction may elect to hold it, or sell it in the FTR Auction. The ISO shall settle FTRs only with the registered FTR Holders. At any given time, each FTR shall have only one registered FTR Holder.

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders.

A target allocation of Transmission Congestion Credits for each FTR Holder shall be determined for all applicable FTRs. Each FTR shall be multiplied by the Day-Ahead Price Congestion Component differences for the associated receipt and delivery points. This calculation will result in a positive or negative FTR target allocation. All negative target allocations are obligations to pay. All positive target allocations will be summed for an FTR Holder for the month and compensated as Transmission Congestion Credits under Section III.5.2.5.

III.5.2.5 Calculation of Transmission Congestion Credits.

(a) The total Transmission Congestion Revenue available for the month shall be equal to the sum of: (i) the hourly Day-Ahead Congestion Revenue amounts for the month, (ii) the hourly Real-Time Congestion Revenue amounts for the month plus Congestion Costs collected under Section III.5.1.4, and (iii) the negative FTR target allocations calculated under Section III.5.2.4.

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

(c) If the sum of all the monthly positive target allocations is greater than the Transmission Congestion Revenue for the current month, each FTR Holder shall be assigned a share of the total Transmission Congestion Revenue for the current month in proportion to its total monthly positive target allocations.

III.5.2.6 Distribution of Excess Congestion Revenue.

If there is any Transmission Congestion Revenue at the end of the calendar year, this amount shall be proportionally allocated to any remaining unpaid monthly positive target allocations plus interest on the unpaid monthly positive target allocations in the months of that year, but shall not exceed an amount equal to the unpaid monthly positive target allocation plus interest on the unpaid monthly positive target allocations in the months of the calendar year. Any remaining surplus Transmission Congestion Revenue shall be allocated to the entities who paid Congestion Costs in that calendar year in proportion to the amount of total Congestion Costs paid during the year.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals and Capacity Load Obligation Bilaterals in accordance with this Section III.13.5. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

A resource having a Capacity Supply Obligation seeking to shed that obligation ("Capacity Transferring Resource") may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part ("Capacity Supply Obligation Bilateral"), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated ("Capacity Acquiring Resource"), subject to the following limitations

(a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) The Capacity Transferring Resource and the Capacity Acquiring Resource that are parties to a Capacity Supply Obligation Bilateral must be located in the same Capacity Zone, or the path from the Capacity Transferring Resource to the Capacity Acquiring Resource must flow across adjacent Capacity Zones in the direction of the modeled interface constraint(s), as such Capacity Zones and interface constraints are defined following the Forward Capacity Auction conducted for the Capacity Commitment Period to which the transferred Capacity Supply Obligation applies.

(g) If the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating Procedures. The ISO will issue a submission schedule for annual Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. Monthly Capacity Supply Obligation Bilaterals may only be submitted and confirmed after the results of the third annual reconfiguration auction have been issued (except as described in Section III.13.4.2.1.3(c)) and prior to the closing of the monthly Capacity Supply Obligation Bilateral window, which will occur prior to the monthly reconfiguration auction. ISO New England will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO during the same submittal window and no later than the same deadline that applies to submission of the Capacity Supply Obligation Bilateral.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met.

(b) Each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation outage information, and will include transmission security studies. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource. The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation ("Capacity Load Obligation Transferring Participant") may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone ("Capacity Load Obligation Bilateral") to any Market Participant seeking to acquire a Capacity Load Obligation ("Capacity Load Obligation Acquiring Participant"). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Supplemental Availability Bilaterals.

A resource's availability score during a Shortage Event may be supplemented by entering into a Supplemental Availability Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Designation of Supplemental Capacity Resources.

III.13.5.3.1.1. Eligibility.

Only Generating Capacity Resources that are not Intermittent Power Resources or Settlement Only Resources may be designated as Supplemental Capacity Resources. A Generating Capacity Resource may be designated as a Supplemental Capacity Resource in a MW amount up to the difference between the resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales submitted in accordance with Section III.1.10.7(f) from that resource or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented) and its Capacity Supply Obligation in each day of the term in which it is designated to be a Supplemental Capacity Resource.

III.13.5.3.1.2. Designation.

The designation of a Supplemental Capacity Resource must be made by the resource's Lead Market Participant. The designation shall indicate the term for which the resource is designated as a Supplemental Capacity Resource, which shall be in Operating Day increments, no less than one Operating Day, and no greater than one calendar month. Such designation shall indicate the MW amount being designated as a Supplemental Capacity Resource, and the Capacity Zone in which the resource is located. Such designation must be submitted to the ISO no later than the deadline for the submission of Supply Offers in the Day-Ahead Energy Market for the first Operating Day of the indicated term.

III.13.5.3.1.3. ISO Review.

The ISO shall review the information provided in submission of the designation as a Supplemental Capacity Resource, and shall reject the designation for any of the hours in which any of the provisions of this Section III.13.5.3.1 are not met.

III.13.5.3.1.4. Effect of Designation.

Regardless of whether it ever becomes subject to a Supplemental Availability Bilateral as described in Section III.13.5.3.2, the portion of a resource designated as a Supplemental Capacity Resource is subject to the same energy market offer requirements applicable to a resource having a Capacity Supply Obligation as described in Sections III.13.6.1.1.1 and III.13.6.1.1.2 for the entire term indicated in the designation described in Section III.13.5.3.1.2.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must be located in the same Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Bilateral, a Supplemental Availability Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Bilateral is to modify the Supplemented Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources.

III.13.6.1.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(a) the sum of the Generating Capacity Resource's notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or

(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with good utility practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;

(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.

The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

The offer requirements of Section III.13.6.1.2.1 will not apply to External Transactions associated with the VJO and NYPA Import Capacity Resources specified in Section III.13.1.3.3(c) for the duration of the contract provided the transactions are self-scheduled in both the Day-Ahead Energy Market and Real-Time Energy Market. If the energy associated with these contracts is not self-scheduled, the offer requirements and provisions of this section will apply to the applicable contract.

(a) All priced External Transactions associated with an Import Capacity Resource with a Capacity Supply Obligation must be offered each hour at or below the greater of either: (1) the offer threshold specified in Section III.13.6.1.2.1(b) for the Operating Day; (2) the offer threshold determined for the prior Operating Day; and (3) for any priced External Transactions from the New York Control Area the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface.

(b) A daily offer threshold will be determined for each Operating Day and will apply to each hour of the Operating Day. From June 1, 2010 to May 31, 2013 the daily offer threshold is equal to the product of the PER Proxy Unit heat rate as described in Section III.13.7.2.7.1.1.1(b)(iii) and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation of day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis. After May 31, 2013 the daily offer threshold is equal to the product of the applicable Forward Reserve Heat Rate as described in Section III.9.6.2 and the lower of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis.

(c) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.

(d) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to 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.

III.13.6.1.2.2. Additional Requirements for Certain Import Capacity Resources.

The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;

(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;

(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.

(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.

III.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.

Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with the requirements in this Section III.13.6.1.2.3 may be subject to sanctions pursuant to Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.2 for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.

(a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.

(b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.1.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.

(c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.

(d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

III.13.6.1.3. Intermittent Power Resources.

III.13.6.1.3.1. Energy Market Offer Requirements.

Intermittent Power Resources may submit offers into the Day-Ahead Energy Market. Such resources are required to submit offers for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.1.4.1. Energy Market Offer Requirements.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.4.2. Additional Requirements for Settlement Only Resources.

Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.1.5. Demand Resources.

Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

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. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO dispatch instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, must Self-Schedule in order to participate in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. Intermittent Settlement Only Resources and Non-Intermittent Settlement Only Resources.

III.13.6.2.4.1. Energy Market Offer Requirements.

A Settlement Only Resource may not submit an offer into the Day-Ahead Energy Market or the Real-Time Energy Market.

III.13.6.2.4.2. Additional Requirements for Settlement Only Resources.
Settlement Only Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) such resources are not subject to outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals.

III.13.6.2.5. Demand Resources.
Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

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 subject to any availability penalties under Section III.13 of this Tariff by such a request for failure to provide energy from that capacity that is not subject to a Capacity Supply

Obligation. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a resource.

III.13.7. Performance, Payments and Charges in the FCM.

During each month within each Capacity Commitment Period ("Obligation Month"), each resource that acquired or shed a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will be subject to payments, charges, penalties and adjustments for such activity. In addition, all resources with a Capacity Supply Obligation as of the beginning of the Obligation Month shall have their performance measured throughout the month, based on the resource's availability during any Shortage Events in the Obligation Month.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Performance Measures.

III.13.7.1.1. Generating Capacity Resources.

During each Capacity Commitment Period, each Generating Capacity Resource having a Capacity Supply Obligation for that Capacity Commitment Period (or any portion thereof) will have its performance measured during each Obligation Month based on the resource's availability during any Shortage Events during the month.

III.13.7.1.1.1. Definition of Shortage Events.

(a) A Shortage Event is any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.

(b) In an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone.

(c) An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.

III.13.7.1.1.1.A Shortage Event Availability Score.

For each Shortage Event, the ISO shall calculate a Shortage Event Availability Score for each resource, as follows: For each hour containing any portion of the Shortage Event, the ISO shall multiply the resource's hourly availability score by the number of minutes of the Shortage Event in that hour, and then divide the product by the total number of minutes in the Shortage Event. The resulting values for each hour shall then be added together to determine the resource's Shortage Event Availability Score.

III.13.7.1.1.2. Hourly Availability Scores.

The ISO shall calculate an availability score for each resource for each hour that contains any portion of a Shortage Event. A resource's availability score for an hour, expressed as a percentage which may not exceed 100 percent, shall be the sum of the resource's available MW in that hour plus any adjustments pursuant to Section III.13.7.1.1.4 divided by the resource's Capacity Supply Obligation. In the event that there are no Shortage Event hours during a month, no availability penalties will be assessed.

III.13.7.1.1.3. Hourly Available MW.

A resource's available MW in each hour that contains any portion of a Shortage Event shall be determined pursuant to the provisions of this Section III.13.7.1.1.3, provided, however, that in no case shall a resource's available MW in an hour exceed that resource's CNR Capability (reduced by the hourly integrated delivered MW for any External Transaction sale or sales from that resource or reduced by the resource's capacity obligation in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented).

(a) For a resource that is on-line with a metered output greater than zero and following ISO dispatch instructions, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(b) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification time plus cold start time of thirty minutes or less, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(c) For a resource that is off-line with a metered output equal to zero and available for dispatch and following ISO dispatch instructions and has a cold notification plus cold start-up time of less than or equal to 12 hours (16 hours, during the first five Capacity Commitment Periods for resources with notification plus start-up times greater than 12 hours as of June 16, 2006) and the output, up to the Capacity Supply Obligation, was competitively offered into the Energy Market (i.e., capacity from the listed portion of the resource was offered at or below the appropriate Reference Level plus applicable conduct thresholds) but was not committed by the ISO and was consequently unavailable within 30 minutes, the available MW in an hour shall be the resource's Economic Maximum Limit, as submitted or redeclared by the Lead Market Participant.

(d) For a resource that is off-line but not meeting the requirements of either Section III.13.7.1.1.3(b) or Section III.13.7.1.1.3(c), the available MW in an hour shall be zero.

(e) For a resource that is on-line but not able to follow ISO dispatch instructions, the available MW in an hour shall be the resource's metered output for the hour.

(f) Where a resource is not committed due to an outage or derate of transmission equipment within the New England Control Area, other than an outage or de-rate of transmission equipment that is controlled by the owner of the resource or that constitutes a radial lead to a resource in the New England Control Area (other than radial leads to Wyman 4 and Stony Brook), that resource's available MW in an hour shall not be reduced as result. Maine Independence Station shall be considered available when derated or not committed because of a transmission constraint.

(g) Where a resource is denied a self-schedule request by the ISO and therefore was not available in the Real-Time Energy Market, that resource's available MW in an hour shall not be reduced as a result.

(h) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation and cannot conduct its capability audit by the first day of the Obligation Month, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(i) Where a New Generating Capacity Resource that has cleared in the Forward Capacity Auction has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, that resource's available MW in an hour shall not be reduced as a result (i.e., the resource shall not be subject to an availability penalty as a result).

(j) Where a resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), that resource will have its hourly available MW reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

III.13.7.1.1.4. Availability Adjustments.

(a) A resource's hourly availability score may be increased using a Supplemental Availability Bilateral as described in Section III.13.5.3. Where all of the requirements of Section III.13.5.3 are met, the amount of available MW from the Supplemented Capacity Resource during each hour of the Shortage

Event will be increased by the amount of supplemental capacity specified in the Supplemental Availability Bilateral, provided, however, that only available capacity above the Supplemental Capacity Resource's Capacity Supply Obligation, if any, during each hour of the Shortage Event may be counted as supplemental capacity for the Supplemented Capacity Resource. The sum of these amounts will be counted in determining the availability score of the Supplemented Availability Resource for the Shortage Event.

(b) A resource's hourly availability score may be increased when an asset associated with the resource is on a planned outage that was approved in the ISO's annual maintenance scheduling process or, for resources in an adjacent Control Area assigned to an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented, when a Market Participant notifies the ISO, in accordance with the ISO's annual maintenance scheduling process, that an asset associated with the External Resource is on an outage that was approved in the resource's native Control Area. Market Participants may indicate when submitting a planned outage request that the outage is to be considered exempt as described in ISO New England Operating Procedure No. 5. In such cases the associated resource's hourly available MWs may be increased by an amount up to the outage MWs requested, provided that the resource has not exceeded the maintenance allotment hour limit regarding exempt approved planned outages at the time of the Shortage Event as described in the ISO New England Manuals. In the case of a Settlement Only Resource, a planned outage scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in this subsection.

III.13.7.1.1.5. Poorly Performing Resources.

Prior to the Forward Capacity Auction qualification process, the ISO shall determine whether a resource meets the following two criteria: in the most recent four consecutive Capacity Commitment Periods or the most recent 4 years in which the resource assumed a Capacity Supply Obligation: (a) the resource received 3 annual availability scores of less than or equal to 40 percent; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The annual availability score for each Capacity Commitment Period shall be equal to the average of all availability scores as calculated for each hour during each Shortage Event. If both of these criteria are met, the resource shall be considered a Poorly Performing Resource and shall not be eligible to participate in any subsequent Forward Capacity Auctions, and may not assume an obligation through the reconfiguration auctions, or Capacity Supply Obligation Bilaterals until it either achieves an availability score of 60 percent or higher in three consecutive Capacity Commitment Periods or 3 consecutive years, or demonstrates to the ISO that the reasons for the inadequate availability scores have been remedied. For the purposes of determining whether a resource is a Poorly Performing Resource, its availability score while it is de-listed shall not be considered. For the purposes of returning from poorly performing status, the ISO, at the request of the resource owner, may consider performance while de-listed, but in no case shall the ISO use non-consecutive years for evaluating a resource's performance.

III.13.7.1.2. Import Capacity.

The provisions of this Section III.13.7.1.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). An Import Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) Where the corresponding External Transactions are delivering energy in accordance with ISO dispatch instructions, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(b) Where the corresponding External Transactions have been offered in accordance with the provisions of Section III.13.6.1.2 and is not delivering energy during the hour because the ISO has not requested dispatch of the transaction, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

(c) Where the corresponding External Transactions have not been offered in accordance with the provisions of Section III.13.6.1.2 or have been offered in accordance with the provisions of Section III.13.6.1.2 and are not delivering energy during the hour despite ISO requested dispatch of the transaction, the resource's available MW in the hour shall be zero.

(d) Where the Import Capacity Resource was offered in accordance with the provisions of Section III.13.6.1.2 but cannot make Real-Time deliveries of energy because the relevant external interface is already flowing at its Total Transfer Capability into New England in Real-Time, the resource's available MW in the hour shall be equal to the MW associated with the External Transactions, as submitted by the Market Participant.

III.13.7.1.2.1. Availability Adjustments.

The hourly availability score of an Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource is on a planned outage in the same manner as described in Section III.13.7.1.1.4(b).

III.1.3.7.1.2.A. Import Capacity on External Interfaces with Enhanced Scheduling.

The following available MW determination applies to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. The performance of an Import Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as designed in Section III.13.7.1.1.1. An Import Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.A.1). The available MW in each hour that contains any portion of a Shortage Event shall be determined as follows:

(a) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation in the interval when the ISO requested delivery.

(b) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the available MW of a resource within that Control Area in the interval when the ISO requested delivery and that contains any portion of a Shortage Event shall be established as follows:

(i) The quantity available is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;

(ii) The quantity available is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested delivery.

(c) If the ISO does not request MW of Import Capacity Resources, then the available MW of a resource within that Control Area will be its Capacity Supply Obligation.

III.13.7.1.2.A.1. Availability Adjustments.

When the available MW of an Import Capacity Resource is calculated under Section III.13.7.1.2.A(b), the hourly availability score of any such Import Capacity Resource that qualified as being backed by a single External Resource may be increased when the associated External Resource has complied with the provisions in Section III.13.7.1.1.4(b) for outage scheduling.

III.13.7.1.3. Intermittent Power Resources.

The performance measure for Intermittent Power Resources, including Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.4. Settlement Only Resources.

III.13.7.1.4.1. Non-Intermittent Settlement Only Resources.

A Non-Intermittent Settlement Only Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively. Its available MW in an hour of a Shortage Event shall be the resource's metered output for the hour.

III.13.7.1.4.2. Intermittent Settlement Only Resources.

The performance measure for Intermittent Settlement Only Resources will be included in the determination of their summer and winter Qualified Capacity as described in Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.7.1.5. Demand Resources.

III.13.7.1.5.1. Capacity Values of Demand Resources.

The Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, multiplied by one plus the percent average avoided peak transmission and distribution losses used by the ISO in its calculations of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. Beginning with the Capacity Commitment Period starting June 1, 2012, the Capacity Value of a Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by one plus the percent average avoided peak transmission and distribution losses used to calculate the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears. For the first Forward Capacity Auction, the value of the Installed Capacity Requirement divided by the 50/50 summer system peak load forecast shall be 1.143, and one plus the percent average avoided peak transmission and distribution losses shall be 1.08.

III.13.7.1.5.1.1. Special Provisions for Demand Resources that Cleared in the First and Second Forward Capacity Auctions in which Project Sponsor Elected to have its Capacity Supply Obligation and Capacity Clearing Price Apply for Multiple Capacity Commitment Periods.

For a Demand Resource that cleared in the Forward Capacity auction for the Capacity Commitment Period beginning June 1, 2010 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2010, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.143 and 1.08. For a Demand Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2011 in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period beginning June 1, 2011, the Capacity Value of that Demand Resource for an Obligation Month shall be its Demand Reduction Value for the month as determined pursuant to Section III.13.7.1.5.3 multiplied by the product of 1.161 and 1.08. This special provision shall cease to apply once the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

III.13.7.1.5.2. Capacity Values of Certain Distributed Generation.

For those Distributed Generation resource assets that are capable of generating energy in excess of the facility load and capable of delivering the excess generation to the power grid, if across Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, as appropriate, a Distributed Generation resource asset's monthly average hourly output is greater than the monthly average hourly load of the end-use customer to which the resource is directly connected, the Capacity Value of the portion of output exceeding the customer's load for the month will be the Demand Reduction Value for that portion of the output.

III.13.7.1.5.3. Demand Reduction Values.

A Demand Reduction Value is the quantity of reduced demand, calculated at the Retail Delivery Point, produced by a Demand Resource. All Demand Reduction Values are based on reductions in end-use demand on the electricity network in the New England Control Area coincident with Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, Demand Resource Critical Peak Hours for Critical Peak Demand Resources, Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, or Real-Time Emergency Generation Event Hours for Real-Time Emergency Generation Resources. The Demand Reduction Value of a combined Demand Resource that reduces load and generates output simultaneously for a single facility shall be its Average Hourly Output, which reflects the combined impact of the load reduction and Distributed Generation output on reducing overall end-use demand on the electricity network in the New England Control Area.

III.13.7.1.5.4. Calculation of Demand Reduction Values for On-Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of On-Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource On-Peak Hours in the month. Should a new On-Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan.

III.13.7.1.5.4.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of June, July and August. The summer seasonal Demand Reduction Value shall apply to the months of September, October, November, April and May.

III.13.7.1.5.4.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of On-Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of December and January. The winter seasonal Demand Reduction Value shall apply to the months of February and March.

III.13.7.1.5.5. Calculation of Demand Reduction Values for Seasonal Peak Demand Resources.

Monthly Demand Reduction Values shall be established for the months of June, July, August, December, and January and seasonal Demand Reduction Values for the remaining calendar months. The monthly Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to its Average Hourly Load Reduction or Average Hourly Output over Demand Resource Seasonal Peak Hours in the month. If there are no Demand Resource Seasonal Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be based on the Demand Reduction Value established for the previous month. Should a new Seasonal Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan. A Seasonal Peak Demand Resource supplier 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 Demand Resource Seasonal Peak Hours, provided that the audit results shall not supplant the summer or winter seasonal Demand Reduction Value based on Demand Resource Seasonal Peak Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values for all subsequent months until the month in which Demand Resource Seasonal Peak Hours occur, provided, however, that audit results can not be used to determine the Demand Reduction Value for a month greater than twelve (12) months from the date the audit was conducted. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan set forth in Section III.13.1.4.2.2.3.

III.13.7.1.5.5.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of June, July and August. This summer seasonal Demand Reduction Value will apply to the months of September, October, November, April and May.

III.13.7.1.5.5.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of Seasonal Peak Demand Resources shall be equal to the simple average of its Average Hourly Load Reduction or Average Hourly Output in the months of December and January. This winter seasonal Demand Reduction Value will apply to the months of February and March.

III.13.7.1.5.6. Calculation of Demand Reduction Values for Critical Peak Demand Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December and January, the Demand Reduction Value of Critical Peak Demand Resource shall be equal to its Average Hourly Load Reduction or Average Hourly Output during Demand Resource Critical Peak Hours in the month. If there are no Demand Resource Critical Peak Hours in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Critical Peak Demand Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values, as described above, then the missing data shall be supplemented with engineering estimates or audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Critical Peak Demand Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Demand Resource Critical Peak Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Demand Resource Critical Peak Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values for all subsequent months until the month in which Demand Resource Critical Peak Hours occur, provided, however, that audit results can not be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Engineering estimates and the procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan, as set forth in Section III.13.1.4.2.2.3.

III.13.7.1.5.6.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Critical Peak Demand Resource for September, October, November, April and May shall be equal to:

(i) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of June, July and August if there are no Demand Resource Critical Peak Hours in the month or

(ii) the simple average of:

(a) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of June, July and August and

(b) its Average Hourly Load Reduction or Average Hourly Output across the Demand Resource Critical Peak Hours in the month if there are Demand Resource Critical Peak Hours in the month.

III.13.7.1.5.6.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Critical Peak Demand Resource for February and March shall be equal to:

(i) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of December and January if there are no Demand Resource Critical Peak Hours in the month or

(ii) the simple average of:

(a) the simple average of its Average Hourly Load Reduction or Average Hourly Output in the most recent months of December and January and

(b) its Average Hourly Load Reduction or Average Hourly Output across the Demand Resource Critical Peak Hours in the month if there are Demand Resource Critical Peak Hours in the month.

III.13.7.1.5.7. Demand Reduction Values for Real-Time Demand Response Resources.

Demand Reduction Values are determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Demand Response Resource is the simple average of its Hourly Calculated Demand Resource Performance Values in the month.

If there are no Real-Time Demand Response Event Hours for a Real-Time Demand Response Resource in the months of July, August, or January, the Demand Reduction Value of that resource for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Real-Time Demand Response Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values for the Real-Time Demand Response Resource, then the missing data shall be supplemented with audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Real-Time Demand Response Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Real-Time Demand Response Event Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Real-Time Demand Response Event Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values of a Real-Time Demand Response Resource for all subsequent months until the month in which Real-Time Demand Response Event Hours occur, provided, however, that audit results cannot be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan pursuant to Section III.13.1.4.2.2.3.

III.13.7.1.5.7.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value of a Real-Time Demand Response Resource for September, October, November, April and May shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Values in the most recent months of June, July and August and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value of a Real-Time Demand Response Resource for February and March shall be equal to (i) the simple average of its Demand Reduction Values in the most recent months of December and January if there are no Real-Time Demand Response Event Hours in the month or (ii) the simple average of (a) the simple average of its Demand Reduction Value in the most recent months of December and January and (b) its Demand Reduction Value, established using the method specified in Section III.13.7.1.5.7, across the Real-Time Demand Response Event Hours in the month if there are Real-Time Demand Response Event Hours in the month.

III.13.7.1.5.7.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Demand Response Resource receiving a Dispatch Instruction for a Real-Time Demand Response Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Demand Response Resource's Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Demand Response Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.7.3.1. Determination of the Hourly Real-Time Demand Response Resource Deviation.

An Hourly Real-Time Demand Response Resource Deviation shall be calculated for each Real-Time Demand Response Resource as the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Demand Response Event Hour. The calculation of the Hourly Real-Time Demand Response Resource Deviation shall be determined in a manner that reflects that Real-Time Demand Response Resources are allowed 30 minutes from the beginning of the first Real-Time Demand Response Event Hour in consecutive Real-Time Demand Response Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in the Dispatch Instruction when such resources are dispatched in response to Real-Time Demand Resource Dispatch Hours. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Demand Response Resource Deviation is greater than zero in any Real-Time Demand Response Event Hour, the Hourly Real-Time Demand Response Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.8. Demand Reduction Values for Real-Time Emergency Generation Resources. Demand Reduction Values shall be determined on a monthly basis. For the months of June, July, August, December, and January, the Demand Reduction Value of a Real-Time Emergency Generation Resource shall be the simple average of its Hourly Calculated Demand Resource Performance Values in the month. If there are no Real-Time Emergency Generation Event Hours for a Real-Time Emergency Generation Resource in the months of July, August, or January, the Demand Reduction Value for those months shall be equal to the Demand Reduction Value established for the previous month. Should a new Real-Time Emergency Generation Resource enter service at a time such that there is an incomplete set of performance data for June, July, August, December, or January upon which to establish summer or winter seasonal Demand Reduction Values for the Real-Time Emergency Generation Resource, then the Demand Reduction Value shall be established using audit results pursuant to its Measurement and Verification Plan. A Market Participant with a Real-Time Emergency Generation Resource may conduct an audit of the resource before the end of a month to establish its Demand Reduction Value for a subsequent month in which there are no Real-Time Emergency Generation Event Hours, provided that the audit results shall not replace the summer or winter seasonal Demand Reduction Value based on Real-Time Emergency Generation Event Hours for the applicable season. Audit results can be used to determine the Demand Reduction Values of a Real-Time Emergency Generation Resource for all subsequent months until the month in which Real-Time Emergency Generation Event Hours occur, provided, however, that audit results cannot be used to determine the Demand Reduction Value for a month greater than 12 months from the date the audit was conducted. Procedures for scheduling and conducting an audit must be submitted as part of the Measurement and Verification Plan, pursuant to Section III.13.1.4.2.2.3.

III.13.7.1.5.8.1. Summer Seasonal Demand Reduction Value.

The summer seasonal Demand Reduction Value for the months of September, October, November, April and May shall be equal to the simple average of the Demand Reduction Values in the most recent months of June, July and August if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of September, October, November, April or May, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8, during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.2. Winter Seasonal Demand Reduction Value.

The winter seasonal Demand Reduction Value for the months of February and March shall be equal to the simple average of the Demand Reduction Values in the most recent months of December and January if there are no Real-Time Emergency Generation Event Hours in the month. If there are Real-Time Emergency Generation Event Hours in the months of February or March, the Demand Reduction Value shall be equal to the Demand Reduction Value, established using the method specified in Section III.13.7.1.5.8 during all the Real-Time Emergency Generation Event Hours in the month.

III.13.7.1.5.8.3. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Emergency Generation Resources.

The Hourly Calculated Demand Resource Performance Value shall be computed for each Real-Time Emergency Generation Resource receiving a Dispatch Instruction for a Real-Time Emergency Generation Event Hour. The Hourly Calculated Demand Resource Performance Value shall be computed as (i) the Real-Time Emergency Generation Resource’s Capacity Supply Obligation, divided by (ii) the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, divided by (iii) one plus the percent average avoided peak transmission and distribution losses used in the calculation of the Installed Capacity Requirement for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, and multiplied by (iv) one plus the quotient of Hourly Real-Time Emergency Generation Resource Deviation and the amount of load reduction or output that the Market Participant with the resource was instructed to produce from that resource pursuant to Dispatch Instructions.

III.13.7.1.5.8.3.1. Determination of the Hourly Real-Time Emergency Generation Resource Deviation.

An Hourly Real-Time Emergency Generation Resource Deviation shall be calculated for each Real-Time Emergency Generation Resource as the difference between the Average Hourly Output of the Real-Time Emergency Generation Resource and the amount of output that the Market Participant with the resource was instructed in the Dispatch Instruction to produce in the Real-Time Emergency Generation Event Hour. The calculation of the Hourly Real-Time Emergency Generation Resource Deviation shall be determined in a manner that reflects that Real-Time Emergency Generation Resources are allowed 30 minutes from the beginning of the first Real-Time Emergency Generation Event Hour in consecutive Real-Time Emergency Generation Event Hours in a Dispatch Instruction for the same Operating Day to achieve the load reduction amount indicated in a Dispatch Instruction. The Total Negative Hourly Demand Resource Deviations for each hour shall be calculated as the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. The Total Positive Hourly Demand Resource Deviations for each hour shall be calculated as the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone. If the Hourly Real-Time Emergency Generation Resource Deviation is greater than zero in any Real-Time Emergency Generation Event Hour, the Hourly Real-Time Emergency Generation Resource Deviation shall be multiplied by the lesser of: (i) one, or; (ii) the ratio of the Total Negative Hourly Demand Resource Deviations divided by the Total Positive Demand Resource Deviations in the same Load Zone in the hour or, starting on June 1, 2011, in the same Dispatch Zone in the hour.

III.13.7.1.5.9. Determination of Hourly Calculated Demand Resource Performance Values for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources Starting with the Capacity Commitment Period beginning June 1, 2012.

Starting with the Capacity Commitment Period beginning June 1, 2012, the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3, which is equal to the summer Installed Capacity Requirement divided by the 50/50 summer system peak load forecast as determined by the ISO for the Forward Capacity Auction immediately preceding the Forward Capacity Auction in which the Demand Resource clears, shall be eliminated from the determination of Hourly Calculated Demand Resource Performance Values, with the exception of Demand Resources that cleared in the Forward Capacity Auctions for the Capacity Commitment Periods beginning June 1, 2010 and June 1, 2011, in which the Project Sponsor elected to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared. For Demand Resources with such multi-year Capacity Supply Obligations the divisor described in (ii) of Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3 shall continue to apply until the period elected by the Project Sponsor to have its Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its Demand Resource offer cleared has expired.

**III.13.7.1.6.		Self-Supplied FCA Resources.**

Self-Supplied FCA Resources are subject to the availability penalties and credits as defined by their resource type.

**III.13.7.2.		Payments and Charges to Resources.**

Resources acquiring or shedding a Capacity Supply Obligation shall be subject to payments and charges in accordance with this Section III.13.7.2. Such resources will also be subject to adjustments as detailed in Section III.13.7.2.7.

**III.13.7.2.1.		Generating Capacity Resources.**

**III.13.7.2.1.1.		Monthly Capacity Payments.**

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources or for resources not commercial during an Obligation Month pursuant to Section III.13.7.1.1.3(h); (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment (subject to the adjustments in Section III.13.7.2.7) or charge during the Capacity Commitment Period as follows:

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case described in Section III.13.7.1.1.3(i), the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted pursuant to Section III.13.2.7.3(b) and as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below (the "FCA Payment"). For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

III.13.7.2.2. Import Capacity.

Import Capacity Resources shall receive monthly capacity payments utilizing the same methodology as that used for Generating Capacity Resources set forth in Section III.13.7.2.1.

III.13.7.2.2.A. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity

Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

> Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]
>
> Charge Amount to Capacity Load Obligations in the Capacity Zone where Resource is located = Capacity Clearing Price $_{\text{location of the resource}}$ x Cleared MWs of Export Bid or Administrative Export De-list Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = Capacity Clearing Price $_{\text{location of the resource}}$ x Cleared MWs of Export Bid or Administrative Export De-list Bid]
>
> Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.2.3. Intermittent Power Resources.
An Intermittent Power Resource shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section 13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Power Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.4. Settlement Only Resources.

III.13.7.2.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1.

III.13.7.2.4.2. Intermittent Settlement Only Resources.

Intermittent Settlement Only Resources shall be entitled to monthly payments during the Capacity Commitment Period calculated in the same manner as that used for Generating Capacity Resources as described in Section III.13.7.2.1, except that any reduction in the Capacity Supply Obligation of an Intermittent Settlement Only Resource made pursuant to Section III.13.4.2.1.2.2.2.3 shall be at the same payment rate applicable to the reduced MW, such that there is a net zero payment for the reduced MW.

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1. Demand Resources shall be subject to Demand Resource Performance Penalties and Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f). Real-Time Emergency Generation Resources shall be subject to Demand Resource Performance Penalties and Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-

Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E.9.2.1 or III.E.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not receive monthly capacity payments for the portion of the resource designated as a Self-Supplied FCA Resource. Charges to load associated with Self-Supplied FCA Resources are calculated pursuant to Section III.13.7.3.

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

Hourly PER($/kW) = [(LMP - Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

(b) PER shall be deducted from capacity payments independently of availability penalties.

(c) FCA Payment minus PER may not be negative for any month.

III.13.7.2.7.1.2. Availability Penalties.

Availability penalties shall be assessed for each resource with a Capacity Supply Obligation as of the beginning of the Obligation Month. The penalty will be based on the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Capacity Zone in which the resource is located for the relevant Capacity Commitment Period, regardless of whether the resource assumed the Capacity Supply Obligation through a Forward Capacity Auction, a reconfiguration auction, or a Capacity Supply Obligation Bilateral.

For capacity resources that are partially or fully unavailable during a Shortage Event:

(a) Penalties shall be determined and assessed on a resource-specific basis. Penalties shall be calculated for each Shortage Event during an Obligation Month and assessed on a monthly basis, subject to the availability penalty caps outlined in Section III.13.7.2.7.1.3.

(b) The penalty per resource for each Shortage Event shall be equal to:

Penalty = [Resource's Annualized FCA Payment]*PF*[1 – Shortage Event Availability Score]

Where:

Annualized FCA Payment = the relevant Capacity Clearing Price, as adjusted pursuant to Section III.13.2.7.3(b), multiplied by the resource's Capacity Supply Obligation as of the beginning of the Obligation Month multiplied by 12.

PF = .05 for Shortage Events of 5 hours or less. PF is increased by .01 for each additional hour above 5 hours.

III.13.7.2.7.1.3. Availability Penalty Caps.

The following caps will apply to the total availability penalties assessed to a resource. If a resource with a Capacity Supply Obligation sheds or acquires an obligation outside the relevant Obligation Month, the Annualized FCA Payment shall not be prorated. Caps are resource-specific and partial year assumption or transfer of a Capacity Supply Obligation through Capacity Supply Obligation Bilaterals or reconfiguration auctions does not affect the application of the cap to each resource independently.

(a) **Per Day**. In no case shall the total penalties for all Shortage Events in an Operating Day exceed 10 percent of a resource's Annualized FCA Payment for that Capacity Commitment Period.

(b) **Per Month**. The sum of a resource's penalties arising from unavailability during an Obligation Month may not exceed two and one-half times the Annualized FCA Payment, divided by twelve, for that Obligation Month. The sum of a resource's penalties arising from unavailability due to a single outage of four days or less but spanning two calendar months may not exceed two and one-half times the average of the Annualized FCA Payments, divided by twelve, for both months.

(c) **Per Capacity Commitment Period**. In determining the availability penalties for the Obligation Month, a resource's cumulative availability penalties for a Capacity Commitment Period may not exceed its Annualized FCA Payment (less PER adjustments) for that Capacity Commitment Period.

III.13.7.2.7.1.4. Availability Credits for Capacity Generating Capacity Resources, Import Capacity Resources and Self-Supplied FCA Resources.

On a monthly basis, penalties received from unavailable resources shall be redistributed to Generating Capacity Resources and Import Capacity Resources with Capacity Supply Obligations and to designated Supplemental Capacity Resources without a Capacity Supply Obligation that have a valid Supplemental Availability Bilateral (pursuant to Section III.13.5.3.2) that were available (pursuant to Section III.13.7.1.1.3) in the respective hours on a Capacity Zone basis as follows: For each Obligation Month, the penalties assessed for the Shortage Events during the month will be credited to those resources identified above that were available, in whole or in part, during the Shortage Events, pro-rata by hourly available MW in the relevant Capacity Zones. Self-Supplied FCA Resources shall be eligible to receive their pro rata share of availability penalties paid by other capacity resources.

III.13.7.2.7.2. Import Capacity.

In addition to the adjustment in this section, Import Capacity Resources shall also be subject to the same adjustments as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.2.1. External Transaction Offer and Delivery Performance Adjustments.

In the event that the conditions in Section III.13.6.1.2.1 are not met in any hour of an Operating Day, the Import Capacity Resource will be subject to the provisions in (a) and (b) below. In addition, all Import Capacity Resources will be subject to the provisions in (c) below.

(a) If in any hour of an Operating Day a priced External Transaction associated with an Import Capacity Resource with a Capacity Supply Obligation is offered above both the offer threshold for the Operating Day and the offer threshold of the prior Operating Day, and for any priced External Transactions from the New York Control Area also is offered above the corresponding hourly day-ahead energy price (NYISO Location-Based Marginal Price) at the source interface, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

(b) For every hour of an Operating Day that the total amount offered from all External Transactions associated with an Import Capacity Resource is less than the Import Capacity Resource's Capacity Supply Obligation, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the Capacity Supply Obligation and the total amount of energy offered for that hour and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month. For each Operating Day only the greater of the total penalties in either the Day-Ahead Energy Market or Real-Time Energy Market will be assessed. For the purposes of this section the total energy offered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(c) Except as specified in Section III.13.7.2.7.2.2, for every hour the total energy from an External Transaction associated with an Import Capacity Resource delivered in real-time to the New England Control Area is less than the energy requested, the Market Participant with the Import Capacity Resource will pay a penalty equal to the product of the difference between the quantity requested and the quantity delivered and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of hours in the month.

Any External Transaction submitted under Section III.1.10.7 and associated with an Import Capacity Resource that is determined to be in economic merit during the next-hour scheduling process will be considered a requested transaction and the ISO may request all or a portion of each transaction.

For Import Capacity Resources with a Capacity Obligation at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented (unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.), the requested and delivered MW are determined as follows:

(i) If the native Control Area delivers the total requested MW of Import Capacity Resources, or more than the total requested MW, then the resources within that Control Area will not be evaluated for penalties.

(ii) If the native Control Area delivers less than the total requested MW of Import Capacity Resources, then the resources will be evaluated using the following requested and delivered MW values:

1. The quantity requested is the resource's Capacity Supply Obligation; and
2. The quantity delivered for a resource is determined as follows:
    a. The quantity delivered is zero if the resource is offline in the native Control Area for the interval when the ISO requested delivery;
    b. The quantity delivered is the maximum output available from the resource, as reflected in the resource's offer data, adjusted for any non-New England capacity obligation to which the resource is subject if the resource is online in the native Control Area for the interval when the ISO requested deliver;
    c. For purposes of this determination, the total energy delivered will be adjusted in accordance with Section III.13.7.1.1.4(b).

(iii) If the ISO does not request MW of Import Capacity Resources, then the resources within that Control Area will not be evaluated for delivery penalties.

A Market Participant's total penalty amount for a single Operating Day for each Import Capacity Resource shall be no more than the product of the Import Capacity Resource's Capacity Supply Obligation and the corresponding interface Capacity Clearing Price as adjusted in Section III.13.2.7.3(b), divided by the number of days in the month.

Each Obligation Month the penalty amounts from all Market Participants with Import Capacity Resources will be allocated to all Market Participants based on their pro-rata share of Capacity Load Obligation within each Capacity Zone in the Obligation Month, with each Capacity Zone allocated an amount based on the pro-rata share of total capacity credits within each Capacity Zone.

III.13.7.2.7.2.2. Exceptions.

The exceptions in Sections III.13.7.2.7.2.2.b, c and d do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduled procedures in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.

a) No penalty will be assessed if the applicable external interface is fully loaded in the import direction. If the transfer capability of the applicable external interface is zero in the import direction it will be considered fully loaded for the purpose of this section.

b) No penalty will be assessed if the delivered energy from a priced External Transaction associated with the New York Control Area is less than requested when the Real-Time Energy Market price at the source location (NYISO Location-Based Marginal Price) is higher than the Real-Time LMP at the associated External Node, provided that Operating Procedure No. 4 has not been declared due to a system-wide capacity deficiency.

c) No penalty will be assessed during periods when the ISO has taken action to reduce import transactions due to a Minimum Generation Emergency condition or due to ramping constraints.

d) No penalty will be assessed on the affected external interface during periods when minimum-flow or directional-flow constraints have occurred, when the ISO was unable to utilize the automated check-out processes for the external interface, or when in-hour curtailments have occurred.

III.13.7.2.7.3. Intermittent Power Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.4. Settlement Only Resources.

III.13.7.2.7.4.1. Non-Intermittent Settlement Only Resources.

Non-Intermittent Settlement Only Resources are subject to the same PER adjustments and availability penalties as Generating Capacity Resources as described in Section III.13.7.2.7.1.

III.13.7.2.7.4.2. Intermittent Settlement Only Resources.

Monthly capacity payments to Intermittent Power Resources are subject to PER adjustments but are not subject to any additional availability penalties.

III.13.7.2.7.5. Demand Resources.

III.13.7.2.7.5.1. Calculation of Monthly Capacity Variances.

For each month, the Monthly Capacity Variance of a Demand Resource shall be calculated by subtracting the Demand Resource's Capacity Supply Obligation for the month from the Demand Resource's monthly Capacity Value. If a Demand Resource's Monthly Capacity Variance is zero, the Demand Resource will not be subject to Demand Resource Performance Penalties or Demand Resource Performance Incentives.

III.13.7.2.7.5.2. Negative Monthly Capacity Variances.

With the exception of a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a negative value, the Demand Resource shall be subject to a Demand Resource Performance Penalty equal to the absolute value of the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f). If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a negative value, the Demand Resource Performance Penalty for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31, of the year preceding the Capacity Commitment Period applicable to the Demand Resource for the particular Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particular Capacity Commitment Period.

III.13.7.2.7.5.3. Positive Monthly Capacity Variances.

With the exception of a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared, if a Demand Resource's Monthly Capacity Variance is a positive value, the Demand Resource shall be eligible to receive a Demand Resource Performance Incentive based on the Monthly Capacity Variance multiplied by the Capacity Clearing Price (as adjusted pursuant to Section III.13.2.7.3(b)) in the Forward Capacity Auction for the relevant Capacity Commitment Period or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), provided that the sum of the Demand Resource Performance Penalties in the month is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month. If a Demand Resource that has elected to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that cleared in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which that offer cleared has a Monthly Capacity Variance with a positive value, the Demand Resource Performance Incentive for such a Demand Resource shall be set according to the Capacity Clearing Price applicable to the Demand Resource for the particular Capacity Commitment Period (as adjusted pursuant to Section III.13.2.7.3(b)), indexed using the Handy-Whitman Index of Public Utility Construction Costs or in the case of a Real-Time Emergency Generation Resource, multiplied by the Capacity Clearing Price in the Forward Capacity Auction for the relevant Capacity Commitment Period as described in Section III.13.2.3.3(f), indexed using the Handy-Whitman Index of Public Utility Construction Costs, applicable to the Demand Resource for the particulate Capacity Commitment Period in effect as of December 31 of the year preceding the Capacity Commitment Period, provided that the sum of the Demand Resource Performance Penalties in the month is equal to or greater than the sum of the Demand Resource Performance Incentives in the same month.

III.13.7.2.7.5.4. Determination of Net Payment.

If the sum of the Demand Resource Performance Penalties in a month is less than the sum of the Demand Resource Performance Incentives in the same month, then the total amount of Demand Resource Performance Penalties shall be paid on a pro-rata basis, based on the non-prorated Demand Resource Performance Incentives of each Demand Resource with a positive Monthly Capacity Variance. The total amount of the Demand Resource Performance Incentives in a month can not exceed the total amount of the Demand Resource Performance Penalties in the same month.

The total of the Demand Resource Performance Incentives in a month can not exceed the total of the Demand Resource Performance Penalties in the same month. If the total Demand Resource Performance Penalties in a month exceeds the total Demand Resource Performance Incentives in the same month, the difference shall not be collected from load serving entities (the ultimate purchaser of capacity).

III.13.7.2.7.6. Self-Supplied FCA Resources.

Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied, but shall be subject to the availability penalties and caps applicable to their resource types.

III.13.7.3. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section 13.7.2 paid to resources with Capacity Supply Obligations in the Capacity Zone, plus the sum of reconfiguration auction payments to those resources in the zone that were purchased by the ISO either to support an increase in the Installed Capacity Requirement (net of HQICCs), to meet requirements deferred from the Forward Capacity Auction to the reconfiguration auction, or to replace resources previously selected where the cost of such replacement is assigned to load serving entities in this Section III.13.2.5.2.5, less PER adjustments for resources in the zone as defined in Section 13.7.2.7.1.1, adjusted for any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives as described in Section III.13.7.2.7.5.4, and including any applicable export charges or credits as determined pursuant to Section III.13.7.2.2.A divided by the sum of all Capacity Supply Obligations (except those for resources clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.3.1. Calculation of Capacity Requirement and Capacity Load Obligation.

The ISO shall assign each load serving entity a Capacity Requirement prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Capacity Requirement for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capability Year to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the 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 prior to the start of the 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 prior to the start of the 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 five FCA delivery periods for the purpose of determining the Capacity Requirement for the load associated with the Demand Resource.

III.13.7.3.1.1. HQICC Used in the Calculation of Capacity Requirements.

In order to treat HQICCs as a load reduction, each holder of HQICCs shall have its Capacity Requirement in the Capacity Zone in which the HQ Phase I/II external node is located as specified in Section III.13.1.3 adjusted by its share of the total monthly HQICC amount.

III.13.7.3.1.2. Charges Associated with Self-Supplied FCA Resources.

The capacity associated with a Self-Supplied FCA Resource shall be treated as a credit toward the Capacity Load Obligation of the load serving entity so designated by such resources as described in Section III.13.1.6. The amount of Self-Supplied FCA Resources shall be determined pursuant to Section III.13.1.6.

III.13.7.3.1.3. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.

The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.3.2. Excess Revenues.

Revenues collected from load serving entities in excess of revenues paid 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 minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the total Capacity Supply Obligations obtained in the exporting Capacity Zone and the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone.

The value of CTRs specifically allocated pursuant to Sections III.13.7.3.3.2(c), III.13.7.3.3.4, and III.13.7.3.3.6 shall be calculated as the product of: (i) the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. The value of the specifically allocated CTRs will be deducted from the associated Capacity Zone's portion of the CTR fund. The balance of the CTR fund will then be allocated to the load serving entities as set forth in Section III.13.7.3.3.2.

III.13.7.3.3.2. Allocation of Capacity Transfer Rights.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.3.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

(c) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine Export Interface for as long as Casco Bay continues to pay to support the transmission upgrades. The balance of the CTR fund associated with the Maine Export Interface shall be allocated to load serving entities with a Capacity Load Obligation on the import-constrained side of the Maine Export Interface.

III.13.7.3.3.3. Allocations of CTRs Resulting From Revised Capacity Zones.
The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.3.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.3.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.3.3.4. Specifically Allocated CTRs Associated with Transmission Upgrades.
(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a

specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.3.3.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.3.3.2.

III.13.7.3.3.5. [Reserved.]

III.13.7.3.3.6. Specifically Allocated CTRs for Pool Planned Units.

In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the applicable seasonal claimed capability of the ownership entitlements in such unit. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

III.13.7.3.4. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charge; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund; and (d) any applicable export charges.

SECTION II

MARKET RULE 1

APPENDIX F

NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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III.F.2.4 Credits for Pool-Scheduled External Transactions Sales or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (Pumps Only)

III.F.2.4.1 Real-Time NCPC Credit Eligibility for Pool-Scheduled External Transactions Sales (priced exports)

III.F.2.4.2 Information Retrieved

III.F.2.4.3 Day-Ahead Bid Amount

NCPC ACCOUNTING

III.F.1. Overview.

Accounting for the provision of Operating Reserve and Replacement Reserve is performed on a daily basis. A generating Resource of a Market Participant that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Day-Ahead Energy Market subject to limitations when the Supply Offer includes Self-Scheduled hours as discussed in Section III.F.1.1.1. A generating Resource of a Market Participant, including a Local Second Contingency Protection Resource, that is capable of providing Operating Reserve, Replacement Reserve or VAR support is eligible to receive NCPC Credits in the Real-Time Energy Market provided that the Resource satisfies the criteria specified in Sections III.F.1.1.2 and III.F.2.1.7 below.

NCPC Credits are also provided for dispatchable External Transactions (both purchases and sales)(excluding Coordinated External Transactions) for Increment Offers and Decrement Bids at External Nodes, for generating units operating as Synchronous Condensers at the direction of the ISO, for Dispatchable Asset Related Demand Resources (pumps only) that are not Self-Scheduled, for cancellation of generating Resources that are Pool-Scheduled Resources and for generating units backed down for the purposes of providing Operating Reserve or VAR support.

NCPC calculations shall be performed separately for the Day-Ahead and Real-Time Energy Markets.

III.F.1.1. Effect of Self-Schedules on NCPC Credits

III.F.1.1.1 Ineligibility for NCPC Credits (Day-Ahead Energy Market).

In the Day-Ahead Energy Market, the Resource's Self-Scheduled hours shall be the Self-Scheduled hours submitted in the Supply Offer.

(a) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation, a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Day-Ahead NCPC Credit for the Operating Day if its Supply Offer contains two blocks of contiguous Self-Scheduled hours separated by less than the Resource's minimum down time. For purposes of this calculation, a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days, or crosses the boundary between two Operating Days as described in (a) above, and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Day-Ahead NCPC Credit for the second Operating Day unless the contiguous block of non Self-Scheduled hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

III.F.1.1.2 Ineligibility for NCPC Credits (Real-Time Energy Market).

In the Real-Time Energy Market, the Self-Scheduled hours for the purpose of determining NCPC Credit eligibility shall be the Self-Scheduled hours from the Day-Ahead Schedule as modified in the Re-Offer electronic bidding (the Real-Time schedule as of 18:00 hours of the day prior to the Operating Day), including any redeclaration of Self-Scheduled hours by a Market Participant pursuant to Section 8 of ISO New England Manual-11.

(a) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if its Supply Offer (submitted either in the Day-Ahead Energy Market or during the Re-Offer Period) contains a Self-Schedule that is for fewer contiguous hours than its minimum run time. For purposes of this calculation a contiguous block of Self-Scheduled hours starting in hour 1 shall qualify as long as the number of Self-Scheduled hours when added to the hours on-line at the end of the previous Operating Day equals or exceeds the Resource's minimum run time and a contiguous block of Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first day but may result in the Resource not being eligible in the second Operating Day as described in subsection (c).

(b) A generating Resource will not be eligible for Real-Time NCPC Credit for the Operating Day if it submits (as a Supply Offer in the Day-Ahead Energy Market or during the Re-Offer Period) two Self-Schedules separated by less than the Resource's minimum down time. For purposes of this calculation a contiguous block of non Self-Scheduled hours that crosses the boundary into a second Operating Day shall qualify in the first Operating Day as meeting the minimum down time requirement but may result in the Resource not being eligible in the second Operating Day as described in subsection (d).

(c) If a contiguous block of Self-Scheduled hours begins on the boundary between two Operating Days or crosses the boundary between two Operating Days and the Resource did not satisfy its minimum run time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum run time.

(d) If a contiguous block of non Self-Scheduled hours crosses the boundary between two Operating Days and the Resource did not satisfy its minimum down time in Real-Time during the first Operating Day, the generating Resource will not be eligible for Real-Time NCPC Credit for the second Operating Day unless the contiguous block of hours beginning in the first hour of the second Operating Day equals or exceeds the remaining portion of its minimum down time.

(e) For purposes of the above determinations, the minimum run time portion of a Real-Time Commitment Period commences with the first hour of the Real-Time Commitment Period in which the actual metered output of the generating Resource equals or exceeds 75 percent of the generating Resource's Economic Minimum Limit; provided that, if the Resource is a Fast Start Generator that never reaches 75 percent of its Economic Minimum Limit during its Real-Time Commitment Period, its minimum run time will commence with the first hour in which it has positive output. Each Real-Time Commitment Period is evaluated separately for the purpose of determining NCPC Credit eligibility.

The Real-Time NCPC Credit eligibility criteria set forth in subsections (a) through (e), above, shall be waived for additional hours of operation that result from an ISO request for extension of the Resource's operating schedule.

III.F.2. NCPC Credits.

NCPC Credits are calculated for each of the following situations:

(1) Pool-Scheduled Resources (Generators), including Local Second Contingency Protection Resources (Generators) and External Transactions (Day-Ahead and Real-Time Energy Markets), other than Coordinated External Transactions; Increment Offers and Decrement Bids cleared at External Nodes.

(2) Pool-Scheduled Resources (Synchronous Condensers and Special Constraint Resources ("SCR") - Real-Time Energy Market)

(3) Canceled Pool-Scheduled Resources (Real-Time Energy Market)

(4) Resources postured for reliability purposes (Real-Time Energy Market)

(5) Dispatchable Asset Related Demand Resources (pumps only) that are postured for reliability purposes in Real-Time.

(6) Self-Scheduled generating Resources providing Operating Reserves by operating in accordance with Dispatch Instructions in non-Self-Scheduled hours or at levels above the Self-Scheduled MW in Self-Scheduled hours during an Operating Day in which they have offered a contiguous block of Self-Scheduled hours, which meet the criteria for such Self-Schedules set forth in Section III.F.1, at least equal to their minimum run times.

III.F.2.1. Credits for Generating Resources.

For each Operating Day, the ISO calculates the NCPC Credit due each Market Participant for generating Resources.

In the Day-Ahead Energy Market, eligible generating Resources shall receive Day-Ahead NCPC Credits for all hours that are not Self-Scheduled. Except as otherwise provided in this Appendix F, all eligible generating Resources are eligible except generating Resources that have Self-Scheduled hours that do not meet the criteria set forth in Section III.F.1.1.1 are ineligible for Day-Ahead NCPC Credit. For purposes of the Day-Ahead NCPC Credit calculations, the Self-Scheduled hours shall be the Self-Scheduled hours in the Participant's Supply Offer.

In the Real-Time Energy Market, an eligible generating Resource is eligible to receive Real-Time NCPC Credits for all hours that are not Self-Scheduled and for MW amounts in excess of the Self-Scheduled MW for Self-Scheduled hours when the Resource operates above the Self-Scheduled MWs at the ISO's request. A generating Resource is not eligible to receive Real-Time NCPC Credits for any hour in which the Resource is ramping up from an off-line state prior to being released for dispatch, or ramping down after receiving a shutdown order. Self-Scheduled hours include hours when the Resource is ramping up to a Self-Scheduled hour from an off-line state, or down from a Self-Scheduled hour to an offline state and hours when the Resource is Self-Scheduled for Regulation. Eligible generating Resources shall consist of Pool-Scheduled Resources and Self-Scheduled Resources that meet the criteria in Section III.F.1.1.2 and any generating Resources specifically made eligible for Real-Time NCPC Credits in other Sections of this Market Rule 1.

III.F.2.1.1 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

III.F.2.1.2 Hourly Day-Ahead Offer Amount.

The ISO calculates the generating Resource's hourly Day-Ahead offer amount based on its Day-Ahead Offer Data that was utilized by the ISO in making the initial commitment decision and the generating Resource's cleared Day-Ahead MWh for that hour.

For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

(a) The ISO accounting process applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Resource Offer Data and if the Start-Up Fee is applicable for the MWh and status of the Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource Day-Ahead and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant. The Start-Up Fee will be associated with the first hour of the Resource's minimum run time on the day for which the Resource is committed. The Start-Up Fee will always be on the same Operating Day for both the Day-Ahead and Real-Time Energy Markets for purposes of calculating Real-Time NCPC Charges/Credits.

(b) Day-Ahead NCPC Credit calculations reflect the Start-Up Fee for the appropriate hot, intermediate, or cold state of the generating unit as it was scheduled in the Day-Ahead Energy Market.

III.F.2.1.3 Hourly Day-Ahead Value.

The ISO *calculates* the generating Resource's hourly Day-Ahead value as: generating Resource cleared Day-Ahead MWh * Day-Ahead LMP

III.F.2.1.4 Daily Day-Ahead Credit.

The ISO calculates the daily Day-Ahead credit for each generating Resource as follows:

(a) Sum hourly Day-Ahead offer amounts, including applicable No-Load Fees and Start-Up Fees, for the day.

(b) Sum hourly Day-Ahead values for the day.

(c) Day-Ahead credit equals any portion of the generating Resource's total Day-Ahead offer amount in excess of its total Day-Ahead value.

III.F.2.1.5 Day-Ahead Credit Allocation.

The ISO allocates the Day-Ahead credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource was scheduled and was eligible for NCPC Credit pro-rata based on Day-Ahead Load Obligations as follows:

Hourly Credit = Daily Credit * (Day-Ahead Load Obligations in scheduled hour) / (Total Day-Ahead Load Obligations in all scheduled hours))

[Note: Each credit is allocated back retaining its flag (Local Second Contingency Protection Resource, VAR etc.)]

III.F.2.1.6 Day-Ahead NCPC Credit: Hourly Market Participant Credit; Operating Day Total.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credit and the total Day-Ahead NCPC Credit for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset.

(b) For each scheduled hour, if the generating Resource is flagged specifically for the provision of VAR or voltage support, the Market Participant's share of Day-Ahead VAR credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits for all generating Resources for that Operating Day.

(c) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Day-Ahead VAR credits is equal to

50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Day-Ahead Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead VAR credits and all Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day.

(d) For each scheduled hour, if the generating Resource is not flagged as a Local Contingency Protection Resource or VAR, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Day-Ahead NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.7 Real-Time NCPC Credit Eligibility.
The ISO determines eligibility for Real-Time NCPC Credits. The following operating guidelines are used in the determination of Real-Time NCPC Credit eligibility:

(a) Generating Resources must be following Dispatch Instructions. For any hour that the generating Resource is not following Dispatch Instructions and the difference between the generating Resource's energy value, in dollars, and energy offer amount, in dollars, (in this case, energy offer amount includes No-Load Fee and incremental energy price and does not include any Start-Up Fee) in that hour is negative, the generating Resource's energy offer amount, in dollars, and energy value, in dollars, in that hour is excluded from the Real-Time NCPC Credit calculations.

(b) Generating Resources that trip during their Real-Time Commitment Periods are treated as set forth below:

(i) If the generating Resource trips during its minimum run time period and the generating Resource is otherwise eligible to receive Real-Time NCPC Credit, the Resource will be eligible for Real-Time NCPC Credit for the period beginning with the start of the Real-Time Commitment Period and ending at the time of the trip. For purposes of determining such generating Resource's eligibility for Real-Time NCPC Credit, such generating Resource shall be eligible to recover a portion of its Start-Up Fee equal to the applicable Start-Up Fee multiplied by the quotient (not to exceed 1) of the generating Resource's hours of operation during the current Real-Time Commitment Period and the generating Resource's minimum run time (Start-Up Fee* (Hours of operation/minimum run time)).

(ii) If the generating Resource trips after its minimum run time has been satisfied and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource will be eligible to receive Real-Time NCPC Credit for hours that were not Self-Scheduled during that Real-Time Commitment Period.

(iii) If the generating Resource trips, is requested to restart by the ISO, and returns to operate as requested, and the generating Resource is otherwise eligible to receive Real-Time NCPC Credits, the generating Resource is eligible to receive Real-Time NCPC Credits (including Start-Up Fee, No-Load Fee and incremental Energy price) for the new Real-Time Commitment Period.

(iv) Generating Resources that trip and return to operate that are not requested to restart by the ISO are treated as Self-Scheduled Resources and are not eligible for Real-Time NCPC Credits (Start-Up Fees and No Load Fee) for the new Real-Time Commitment Period.

When a generating Resource trips off line as the result of an equipment failure that involves equipment located on the electric network beyond the low voltage terminals of the generating unit step-up transformer, the ISO shall not treat the event as a trip for the purposes of determining the generating Resource's eligibility for Real-Time NCPC Credit for that Real-Time Commitment Period. It is the responsibility of the Lead Market Participant for the generating Resource to inform the ISO at xtrip@iso-ne.com within thirty (30) days that the trip was the result of such a transmission-related event.

(c) If a generating Pool-Scheduled Resource is otherwise eligible to receive Real-Time NCPC Credit and waives its minimum run time at the ISO's request, or if the ISO accepts an offer from a generating Pool-Scheduled Resource that is otherwise eligible to receive Real-Time NCPC Credit to waive its minimum run time and the ISO agrees to allow the Resource to shut down prior to completion of the generating Pool-Scheduled Resource's minimum run time:

(i) The generating Pool-Scheduled Resource shall be considered to have completed its minimum run time in calculating Real-Time NCPC Credits for which the generating Pool-Scheduled Resource is otherwise eligible; and

(ii) The generating Pool-Scheduled Resource's applicable Start-Up Fee shall be included in the calculation of said NCPC Credits.

III.F.2.1.8 Hourly Real-Time MWh.

The ISO determines the generating Resource's hourly Real-Time MWh based on the values submitted to the ISO by the Assigned Meter Reader for that hour.

III.F.2.1.9 Hourly Real-Time Energy Offer Amount.

The ISO calculates the generating Resource's hourly Real-Time energy offer amount based on its prices contained in the Supply Offer (if said Supply Offer has been mitigated, the mitigated Supply Offer shall be used for this calculation) for all eligible hours. For pool-scheduled hours, the Supply Offer price is multiplied by the lesser of the generating Resource's Desired Dispatch Point (provided that any Desired Dispatch Point below the Resource's Economic Minimum Limit will be deemed equal to the Economic Minimum Limit) or its actual metered output for that hour less the Resource's cleared Day-Ahead MWh. For generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours, the Supply Offer price (excluding the Start-Up Fees and No-Load Fee) is multiplied by the lesser of the DDP or actual metered quantity less the greater of the Resource's Self-Scheduled MW or the Resource's cleared Day-Ahead MWh. Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the output of the unit that is attributable to its submittal of a Self-Schedule for Regulation. For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

III.F.2.1.10 Application of Start-Up Fee and Hourly No-Load Fee.

The ISO applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Generator Offer Data and if the Start-Up Fee is applicable for the MWh and status of the generating Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource in Real-Time and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant or if that Participant's Resource was scheduled in the Day-Ahead Energy Market. The No-Load Fee is not applicable in any hour if the total number of hours that the Resource cleared in the Day-Ahead Energy Market is greater than the total number of hours that the Resource had actual generation greater than zero.

If the total number of hours that the Resource had actual generation greater than zero is greater than the total number of hours that the Resource cleared in the Day-Ahead Energy Market, the No-Load Fees would be applicable once the total number of hours that the Resource actually ran in Real-Time exceeded the total number of hours that the Resource cleared in the Day-Ahead Energy Market.

III.F.2.1.11

If applicable, when a generating Resource is started during the day at the direction of the ISO, the generating Resource's Real-Time offer amount calculated for that day includes its Start-Up Fee based on the appropriate hot, intermediate, or cold state of the generating Resource. For generating Resources that start generating for the ISO from a condensing state, the applicable Start-Up Fee for that generating Resource shall be the Start-Up Fee submitted that is associated with the hot state of the unit.

III.F.2.1.12

If applicable, the generating Resource's Real-Time calculated offer amount includes its hourly No-Load Fee prorated for all hours of operation as follows, using a 10% tolerance:

> If: lesser of (Real-Time MWh or Desired MW) < .9 * (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time),
> Then: hourly No-Load Fee is prorated by (lesser of (Real-Time MWh or Desired MW) / (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time).

III.F.2.1.13 Generating Resource Hourly Real-Time Value.

The ISO calculates the generating Resource's hourly Real-Time value for all eligible hours as:

> ((generating Resource metered value – max (generating Resource cleared Day-Ahead MWh, generating Resource Real-Time Self-Schedule MWh)) * (Real-Time LMP at generating Resource Node)) + generating Resource Regulation Opportunity Cost.

III.F.2.1.14 Generating Resource Daily Real-Time Credits.

The ISO calculates the daily Real-Time credits for each generating Resource as follows:

(a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day.

(b) Sum hourly Real-Time values for the day.

(c) Real-Time credits are equal to any portion of the generating Resource's total Real-Time offer amount in excess of its total Real-Time value.

III.F.2.1.15 Real-Time Credit Allocation.
The ISO allocates the Real-Time credits, for each generating Resource for each Operating Day, back to each hour in the Operating Day in which the generating Resource actually operated and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * (Real-Time Load Obligation in operating hour) / Total Real-Time Load Obligations in all operating hours)

III.F.2.1.16 Real-Time NCPC Credits; Hourly Market Participant Credit; Operating Day Total.
The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the generating Resource is flagged as providing Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time SCR NCPC Credits for all generating Resources for that Operating Day,

(b) For each scheduled hour, if the generating Resource is flagged as a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(c) For each scheduled hour, if the generating Resource is flagged as a VAR Generator, the Market Participant's share of Real-Time VAR credits is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits for all generating Resources for that Operating Day,

(d) For each scheduled hour, if the generating Resource is flagged as both VAR and a Local Second Contingency Protection Resource, the Market Participant's share of Real-Time VAR credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset and the Market Participant's share of Real-Time Local Second Contingency Protection Resource NCPC Credits is equal to 50% of the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time VAR credits and all Real-Time Local Second Contingency Protection Resource NCPC Credits for all generating Resources for that Operating Day,

(e) For each scheduled hour, if the generating Resource is not flagged as a Local Second Contingency Protection Resource or VAR, the Market Participant's share of Real-Time economic NCPC Credit is equal to the Real-Time credit in that hour multiplied by the Market Participant's Ownership Share in the Generator Asset. The ISO then sums all Real-Time NCPC Credits for all generating Resources for that Operating Day.

III.F.2.1.17 Addition of Hourly Shortfall Payments.

Generating Resources that are Pool-Scheduled Resources in the Day-Ahead Energy Market that are available, can deliver Energy and are not Postured, but are not economically dispatched in Real-Time and have not changed their incremental energy offers during the re-offer period, are eligible to receive the difference between the Real-Time and Day-Ahead LMP at the generator bus times the Day-Ahead scheduled MWh for hours when the Real-Time LMP is greater than the Day-Ahead LMP. Any payments made for each hourly shortfall are added to the total Real-Time economic NCPC Credits, Real-Time Local Second Contingency Protection Resource NCPC Credits or Real-Time VAR credits, as applicable, for the applicable Operating Day.

III.F.2.1.18 Addition of Minimum Generation Emergency Credits.

When a Minimum Generation Emergency has been declared (see Section 2.5.13.2 of ISO New England Manual M-11), generating Resources that are otherwise eligible to receive Real-Time NCPC Credits may be eligible to receive Minimum Generation Emergency Credits as provided below:

(a) Minimum Generation Emergency Credits will only be available in the Data Reconciliation Resettlement of the monthly services customer bill for the Operating Day(s) in which the Minimum Generation Emergency was declared.

(b) Minimum Generation Emergency Credits must be requested by sending a letter to the ISO's Market Support Services Department (custserv@iso-ne.com) within 20 business days after issuance of the monthly services customer bill that covers the hours of Minimum Generation Emergency for which a claim is being made. Requests received later than 20 business days after the issuance of the monthly services customer bill that includes the Minimum Generation Emergency hours for which a claim is being made will not be accepted.

(c) The lesser of the generating Resource's Desired Dispatch Point or actual metered output must be above the generating Resource's Economic Minimum Limit for each hour for which Minimum Generation Emergency Credit is requested.

(d) The Minimum Generation Emergency Credit for each eligible hour will be calculated as follows:

(i) The generating Resource's Economic Minimum Limit will be subtracted from the lesser of the generating Resource's Desired Dispatch Point ("DDP") or Real-Time Generation Obligation. Generating Resources with DDPs above Economic Minimum Limits because they are ramp rate constrained when being dispatched down to their Emergency Minimum Limits will have the result of the above calculation set to zero.

(ii) The result of step (i) will be multiplied by the Supply Offer price (in this case excluding the daily Start-Up Fee but not the hourly No-Load Fee) associated with the appropriate Supply Offer Energy block

(iii) The result of step (ii) will be reduced by any revenue received during that hour in the Real-Time Energy Market due to a non-zero LMP for the hour(s) for which the Minimum Generation Emergency was declared.

(e) Resources receiving Minimum Generation Emergency Credits under this Section III.F.2.1.18 shall be ineligible to receive Real-Time NCPC Credit for the same hour(s).
Charges associated with Minimum Generation Emergency Credits are discussed in Section 3 of this Appendix F.

III.F.2.2. Real-Time Credits for Pool-Scheduled Synchronous Condensers.

For each Operating Day, the ISO calculates the NCPC Credits due each Market Participant for Pool-Scheduled Resources scheduled as Synchronous Condensers.

III.F.2.2.1 Information Retrieved.

The ISO retrieves the following information:

(a) Dispatcher generation scheduling and operations logs

(b) Generator Offer Data

III.F.2.2.2 Duration of Pool-scheduled Periods of Synchronous Condensing Operations.

The ISO calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.

III.F.2.2.3 Condensing Offer Amount.

The ISO calculates each generating Resource's condensing offer amount for each period by multiplying the duration (in hours) by the hourly price to condense as specified in the Offer Data. If no hourly price to condense is listed in the Generator Offer Data, an hourly price of zero will be assumed and no payment will be made.

III.F.2.2.4 Condensing Credit.

When a generating Resource is requested to start condensing from an off-line state, a condensing credit is provided equal to the Resource's condensing Start-Up Fee as specified in the Offer Data.

III.F.2.2.5 VAR Credit.

If a unit is flagged as a VAR Resource and as a Synchronous Condenser, it will be compensated by a VAR credit.

III.F.2.2.6 Market Participant's Real-Time NCPC Condensing Credits.

The ISO calculates the daily Real-Time NCPC condensing credits for each Market Participant by summing all remaining hourly condensing generating Resource offer amounts, including applicable Start-Up Fees, for the Operating Day taking the Market Participant's Ownership Share into account.

III.F.2.2.7 Total Real-Time NCPC Condensing Credits.

The ISO sums the Real-Time NCPC condensing credits for all Market Participants for each Operating Day.

III.F.2.3. Credits for Pool-Scheduled External Transaction Purchases or Increment Offers at External Nodes.

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction purchases (modeled as Supply Offers at External Nodes) or Increment Offers at External Nodes as follows. These calculations only apply to External Transaction purchases submitted that are dispatchable and are submitted as source equals sink, or cleared Increment Offers at External Nodes. Notwithstanding anything to the contrary in this Section III.F.2.3, Market Participants shall not be eligible to receive Real-Time NCPC Credits or Day-Ahead NCPC Credits for Coordinated External Transaction purchases.

III.F.2.3.1

Real-Time NCPC eligibility for pool-scheduled External Transactions Purchases (priced imports).

(a) For each hour that a pool-scheduled External Transaction purchase is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions purchases are only eligible for Real-Time NCPC Credits to the extent that the Real-Time transaction (measured in MWh) exceeds the associated Day-Ahead schedule.

III.F.2.3.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction purchases, and Increment Offers at External Nodes

(c) hourly pool-scheduled Day-Ahead and Real-Time External Transaction purchase offer price curve ($/MWh, MW), and hourly Increment Offer price curve ($/MWh,MW) submitted at External Nodes

(d) Day-Ahead and Real-Time LMPs

(e) Transaction flags (Local Second Contingency Protection Resource)

III.F.2.3.3 Day-Ahead Offer Amount.

The ISO calculates the hourly Day-Ahead offer amount for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the transaction offer price.

III.F.2.3.4 Hourly Day-Ahead Value.

The ISO calculates the hourly Day-Ahead value for each pool-scheduled External Transaction purchase or Increment Offer at an External Node by multiplying the cleared Day-Ahead transaction amount by the Day-Ahead LMP at the applicable External Node.

III.F.2.3.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction purchase or Increment Offer at an External Node as follows:

(a) Day-Ahead offer amounts for the hour

(b) Day-Ahead values for the hour

(c) Day-Ahead NCPC Credits for External Transaction purchases or Increment Offers equal any portion of the import transaction’s hourly Day-Ahead offer amount in excess of its hourly Day-Ahead value; provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction purchases or Increment Offers for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction sales or Decrement Bids for the External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the total External Transaction purchases or Increment Offers at the External Node are not offset by those of the total cleared External Transaction sales or Decrement Bids. The External Transaction purchases megawatts will be offset in order from highest to lowest price.

III.F.2.3.6 [Reserved.]

III.F.2.3.7 Day-Ahead NCPC Credits: Market Participant's Hourly Credits.

The ISO calculates each Market Participant's hourly Day-Ahead NCPC Credits as follows:

For each scheduled hour, the Market Participant's share of Day-Ahead economic NCPC Credits is equal to the Day-Ahead credit in that hour.

III.F.2.3.8 Hourly Real-Time Offer Amount.

The ISO calculates the hourly Real-Time offer amount for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead schedule by the transaction offer price.

III.F.2.3.9 Hourly Real-Time Value.

The ISO calculates the hourly Real-Time value for each pool-scheduled External Transaction purchase by multiplying the scheduled Real-Time transaction amount that exceeds the cleared Day-Ahead transaction MWh amount by the Real-Time LMP of the applicable External Node.

III.F.2.3.10 Real-Time Credits Calculation.

The ISO calculates the daily Real-Time credits for Real-Time External Transaction purchases as follows:

(a) Sum hourly Real-Time offer amounts for the day

(b) Sum hourly Real-Time values for the day

(c) Real-Time daily credit equals the portion of the External Transaction purchase's total daily Real-Time offer amount in excess of its daily Real-Time value.

III.F.2.3.11 Real-Time Credits Allocation.

The ISO allocates the Real-Time credits, for each External Transaction purchase for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.3.12 Real-Time NCPC Credits: Market Participant's Hourly and Operating Day Total. The ISO calculates each Market Participant's hourly Real-Time NCPC Credits and the total Real-Time NCPC Credits for each Operating Day as follows:

(a) For each scheduled hour, if the External Transaction purchase is flagged as Local Second Contingency Protection Resource, the Market Participant's share of Local Second Contingency Protection Resource economic NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time Local Second Contingency Protection Resource NCPC Credits for all External Transaction purchases for that Operating Day,

(b) For each scheduled hour, if the External Transaction purchase is not flagged as Local Second Contingency Protection Resource, the Market Participant's share of Real-Time NCPC Credits is equal to the Real-Time credit in that hour. The ISO then sums all Real-Time NCPC Credits for all External Transaction purchases for that Operating Day.

III.F.2.4. Credits for Pool-Scheduled External Transactions Sales or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (Pumps Only).

For each Operating Day, the ISO calculates the credits due each Market Participant for pool-scheduled External Transaction sales (modeled as Demand Bids at External Nodes) or Decrement Bids at External Nodes and Dispatchable Asset Related Demand Resources (pumps only) as follows. Credits for pool-scheduled External Transaction sales or Decrement Bids at External Nodes only apply to External Transaction sales submitted that are Dispatchable and are submitted as source equals sink, or cleared Decrement Bids at External Nodes. Notwithstanding anything to the contrary in this Section III.F.2.4, Market Participants shall not be eligible to receive Real-Time NCPC Credits and Day-Ahead NCPC Credits for Coordinated External Transaction sales. Dispatchable Asset Related Demand Resources (pumps only) are eligible for NCPC Credits in hours for which they are not Self-Scheduled and are following Dispatch Instructions. Dispatchable Asset Related Demand Resources (pumps only) that are Self-Scheduled for any portion of an hour shall be considered Self-Scheduled for the entire hour and shall not be eligible for NCPC Credits in that hour.

III.F.2.4.1

Real-Time NCPC Credit eligibility for pool-scheduled External Transactions Sales (priced exports) is determined as follows:

(a) For each hour that a pool-scheduled External Transaction sale is scheduled in Real-Time based on its Day-Ahead cleared schedule, the transaction is ineligible for Real-Time NCPC Credits; and

(b) Pool-scheduled External Transactions sales are only eligible for Real-Time NCPC to the extent that the Real-Time transaction (measured in MWh) is scheduled to consume more than the associated Day-Ahead schedule.

III.F.2.4.2 Information Retrieved.

The ISO retrieves the following information:

(a) dispatcher transaction logs

(b) Pool-scheduled Day-Ahead scheduled and Real-Time scheduled External Transaction sales (positive values), and Decrement Bids at External Nodes

(c) Pool-scheduled Day-Ahead scheduled consumption and Real-Time actual consumption for Dispatchable Asset Related Demand Resources (pumps only) (positive values)

(d) hourly pool-scheduled Day-Ahead and Real-Time External Transaction Demand Bid cost curve ($/MWh, MW), and hourly Decrement Bid cost curve ($/MWh,MW) submitted at External Nodes

(e) hourly pool-scheduled Real-Time Demand Bid cost curve ($/MWh, MW) for Dispatchable Asset Related Demand Resources (pumps only)

(f) Day-Ahead and Real-Time LMPs

III.F.2.4.3 Day-Ahead Bid Amount.

The ISO calculates the hourly Day-Ahead bid amount for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Demand Bid price.

III.F.2.4.4 Day-Ahead Cost.

The ISO calculates the hourly Day-Ahead cost for each pool-scheduled External Transaction sale or Decrement Bid at an External Node by multiplying the cleared Day-Ahead MWs by the Day-Ahead LMP at the applicable External Node.

III.F.2.4.5 Day-Ahead Credits.

The ISO calculates the hourly Day-Ahead credits for each pool-scheduled External Transaction sale or Decrement Bid at an External Node as follows:

(a) Day-Ahead bid amounts for the hour

(b) Day-Ahead costs for the hour

(c) Day-Ahead NCPC Credits for External Transaction sales or Decrement Bids equal any portion of the sale transaction's hourly Day-Ahead cost in excess of its hourly Day-Ahead bid amount provided, however, that where a Market Participant has submitted and cleared one or more pool-scheduled External Transaction sales or Decrement Bids for a given External Node and hour and the submitting Market Participant or its Affiliate has also submitted and cleared one or more External Transaction purchases or Increment Offers for the same External Node and hour, the Market Participant will be eligible for Day-Ahead External Transaction NCPC Credits solely for any amount by which the megawatts of the External Transaction sales or Decrement Bids at the External Node are not offset by those of the total cleared External Transaction purchases or Increment Offers. The External Transaction sales megawatts will be offset in order from lowest to highest price.

III.F.2.4.6 [Reserved.]

III.F.2.4.7 Real-Time Bid Amount - External Transaction Sale.

The ISO calculates the hourly Real-Time bid amount for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the transaction Demand Bid price.

III.F.2.4.8 Real-Time Bid Amount - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time bid amount for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption less any cleared Day-Ahead consumption by the Dispatchable Asset Related Demand Resources (pumps only) Demand Bid price.

III.F.2.4.9 Real-Time Cost - External Transaction Sale.

The ISO calculates the hourly Real-Time cost for each pool-scheduled External Transaction sale by multiplying the Real-Time transaction amount scheduled in excess of the cleared Day-Ahead transaction amount by the Real-Time LMP of the applicable External Node.

III.F.2.4.10 Real-Time Cost - Dispatchable Asset Related Demand Resources (Pumps Only).

The ISO calculates the hourly Real-Time cost for each Dispatchable Asset Related Demand Resources (pumps only) by multiplying the actual Real-Time consumption hourly deviations from the cleared Day-Ahead amount by the Real-Time LMP of the applicable Node.

III.F.2.4.11 Real-Time Credits - External Transaction Sale.

The ISO calculates the daily Real-Time NCPC Credits for Real-Time External Transaction sales as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals the portion of the External Transaction sale’s total daily Real-Time bid amount that is less than its daily Real-Time cost.

III.F.2.4.12 Real-Time Credits Allocation - External Transaction Sale.

The ISO allocates the Real-Time NCPC Credits, for each External Transaction sale for each Operating Day, back to each hour in the Operating Day in which the External Transaction was scheduled and was eligible for NCPC Credit as follows:

Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.4.13 Real-Time Credits -Dispatchable Asset Related Demand Resources (Pumps Only).
The ISO calculates the daily Real-Time NCPC Credits for Real-Time Dispatchable Asset Related Demand Resources (pumps only) as follows:

(a) Sum hourly Real-Time bid amounts for the day

(b) Sum hourly Real-Time costs for the day

(c) Real-Time NCPC Credit equals any portion of total daily Real-Time costs in excess of its total daily Real-Time bid amount of the Dispatchable Asset Related Demand Resource (pumps only).

III.F.2.4.14 Real-Time Credits Allocation -Dispatchable Asset Related Demand Resources (Pumps Only).
The ISO allocates the Real-Time NCPC Credits, for each Dispatchable Asset Related Demand Resources (pumps only) for each Operating Day, back to each hour in the Operating Day in which the Dispatchable Asset Related Demand Resources (pumps only) was scheduled as follows:
Hourly Credit = Daily Credit * ((Real-Time Load Obligation in operating hour) / (Total Real-Time Load Obligations in all operating hours))

III.F.2.5. Credits for Canceled Pool-Scheduled Resources (Generators).
For each Operating Day, the ISO calculates an NCPC Credit for the cancellation of a start-up prior to the assigned commitment time for any generating Pool-Scheduled Resource that:

(a) Was not scheduled by the ISO in the Day-Ahead Energy Market, and

(b) Was issued Dispatch Instructions to start-up in Real-Time. This cancellation credit is based on values submitted by Market Participants as part of the Resource's Offer Data. The following Offer Data parameters are utilized in the calculation: hot to cold time, hot to inter time, hot startup cost, inter startup cost, cold startup cost, hot notification time, inter notification time, and cold notification time.

III.F.2.5.1 Information Retrieved.
The ISO retrieves the following information:

(a) list of canceled generating Resources (dispatcher log)

(b) Applicable generator Start-Up Fee (hot startup cost, inter startup cost or cold startup cost)

(c) Generator flags (Local Second Contingency Protection Resource, VAR, or SCR)

(d) generation data

III.F.2.5.2 Cancelled Start Credit Calculation.

The ISO credits each Market Participant for cancellation based on a pro-rata share of the applicable generating Resource's Start-Up Fee, and associated notification time parameter (hot, inter, or cold) utilized by the ISO in the original commitment decision. The credit for cancelled starts is calculated as follows:

Cancelled Start Credit = Applicable Generator Start-Up Fee * (1- ((Cancel Time) /(Notification Time))),

Where,

Applicable Generator Start-Up Fee	equals (i) Hot Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is less than the Hot to Inter Time; (ii) Inter Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Inter Time and less than the Hot to Cold Time; or (iii) Cold Startup Cost if the difference in hours between the ISO Commitment Order Time and the unit's last off-line time is greater than or equal to the Hot to Cold Time,
Cancel Time	equals the difference, in hours, between the original ISO Commitment Order Time for the unit and the time at which the ISO cancelled the commitment of the unit. Cancel Time must be less than or equal to Notification Time, otherwise, the Cancelled Start Credit is set equal to zero,
ISO Commitment Order Time	equals the time at which the unit was originally requested to be synchronized to the New England Transmission system,
Notification Time	equals the applicable number of hours required to synchronize the unit to the system as submitted as part of the Generating Resource's Offer Data (Hot Notification Time, Intern Notification Time, or Cold Notification Time), and

Cancelled Start Credit is limited to be no greater than the applicable Start-Up Fee and notification time cannot be longer than 24 hours.

III.F.2.5.3 Real-Time NCPC Credit.

The Real-Time NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in Section III.F.2.5.2 above for all generating Pool-Scheduled Resources that were not originally flagged as a Local Second Contingency Protection Resource or VAR.

III.F.2.5.4 Local Second Contingency Protection Resource NCPC Credit.

The Real-Time Local Second Contingency Protection Resource NCPC Credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.1.13 above for all generating Pool-Scheduled Resources that were originally flagged as Local Second Contingency Protection Resources.

III.F.2.5.5 VAR Credit.

The Real-Time VAR credit for cancelled starts for the Operating Day is equal to the sum of the Real-Time credits calculated in III.F.2.5.2 above for all generating Pool-Scheduled Resources that were originally flagged as VAR.

III.F.2.5.6 Reserved.

III.F.2.5.7 SCR Credits.

The Real-Time SCR credits associated with generating units identified as SCR Resources are billed as provided for in Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

III.F.2.5.8 Example.

An example of the cancelled start calculation is as follows:

> Asset ID ABC was scheduled after the close of the Day-Ahead Energy Market to start at 6:00 am. ISO Cancelled the unit Start Time, in Real-Time, at 4:00 am. Cancel Time Column is calculated by subtracting Start time – Cancel time (6 – 4 = Cancel Time is 2)
> To determine the amount Cancelled Start we look at the Start-Up Fee and we multiply it by 1 minus Cancel Time divided by Time to Start.

III.F.2.6. Credits for Generating Resources and Dispatchable Asset Related Demand Resources (pumps only) Postured for Reliability.

The ISO credits Dispatchable Asset Related Demand Resources (pumps only) for responding to the ISO's request to increase consumption to a level above what would have been consumed during normal economic operation. The ISO credits Postured generating Resources, both pool-scheduled and Self-Scheduled, for responding to the ISO's request to reduce or suspend normal economic operation. A Resource shall be considered postured when it meets the conditions described in the definition of "Postured" in the Tariff. The ISO takes into account any generator Regulation credits associated with the postured generating Resource for the provision of Regulation while postured in calculating the posturing credits for generating Resources. For a Dispatchable Asset Related Demand Resource (pumps only) that is Postured, the posturing credits are calculated in accordance with Section III.F.2.4.

III.F.2.6.1 Information Retrieved.

The ISO retrieves the following information:

(a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)

(b) Generator Offer Data

(c) 5 minute generation data from EMS

(d) Real-Time LMP data

(e) Real-Time Generation Obligation

(f) Generator Regulation credits

III.F.2.6.2 Posturing Credit Calculation.

The ISO credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Daily Energy Restrictions.* For generating Resources without energy restrictions, the posturing credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – GRC

Where

PAG	equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;
AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;
UB	equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;
GRC	(Generator Regulation Credits) is the value calculated under Section 4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28; and

where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Daily Energy Restrictions.* For generating Resources with energy restrictions, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the hour that posturing began and ending at the end of the calendar day,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP - UB) – GRC

Where:

PAG	equals the estimated hourly generation had the generating Resource not responded to Dispatch orders to reduce or suspend operation. Estimated operation for generating Resources following the Day-Ahead schedule prior to the posturing event will be determined by the Day-Ahead schedule. From the start of the posturing event through the end of the calendar day, PAG is set to the

Day-Ahead schedule for as long as available energy would have supported the operation. For generating Resources responding to DDP's in Real-Time or operating under Real-Time Self-Schedule changes prior to the posturing event, PAG will be set assuming economic operation would have occurred during posturing and throughout the day for as long as the available energy would have supported the operation;

AG	equals the actual output of the generating Resource;
ULMP	equals the Real-Time LMP associated with the generating Resource;
UB	equals the Generator Supply Offer price (increment energy price only); and
GRC	is the value calculated under Section 4 of the ISO New England Manual for Market Rule 1 Accounting, M-28.

III.F.2.6.3 Real Time NCPC Credits.

The Real-Time NCPC Credits for posturing for the Operating Day are equal to the sum of the non-VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.2.6.4 Real Time VAR Credits.

The Real-Time VAR credits for posturing for the Operating Day are equal to the sum of the VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

III.F.3. Charges for NCPC

III.F.3.1. Allocation.

The sum of Day-Ahead NCPC Credits for the Day-Ahead Energy Market, excluding the Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes, is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time NCPC Credits (excluding Posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Asset Related Demand Resources that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Asset Related Demand Resources for the Operating Day that result from operation in accordance with the ISO

’s instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource’s Economic Minimum Limit. Real Time NCPC Credits associated with the Posturing of facilities are allocated and charged to Market Participants in proportion to the daily sum of their Real-Time Load Obligations, excluding Real-Time Load Obligation associated with Postured Dispatchable Asset Related Demand Resource (pumps only) operation that is not Self-Scheduled or is not in merit. Notwithstanding anything to the contrary in this Section III.F.3, Coordinated External Transactions shall be excluded from the Real-Time Energy Market NCPC Charge calculation and Day-Ahead Energy Market NCPC Charge calculation.

The sum of Day-Ahead Local Second Contingency Protection Resource NCPC Credits associated with generating Resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region in proportion to the daily sum of their Day-Ahead Load Obligations within each affected Reliability Region. The sum of Real-Time Local Second Contingency Protection Resource NCPC Credits associated with generating units identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged to Market Participants within each affected Reliability Region and, under certain circumstances, to any adjacent Control Area purchasing Emergency energy from the ISO. Charges are allocated in proportion to the daily sum of Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resource (pumps only) Operation that is above its Minimum Consumption Limit) plus applicable Emergency energy sales within each affected Reliability Region.

The sum of Day-Ahead and Real-Time NCPC Credits paid to Market Participants associated with Resources other than SCRs (including Synchronous Condensers and Postured Resources) that have been identified by the ISO as being required to provide voltage support or VAR support are collected from Market Participants in accordance with Schedule 2 of Section II of the Transmission, Markets and Services Tariff. Each Market Participant’s Minimum Generation Emergency Charge is calculated as follows:

(1) For each generating Resource of the Market Participant for which a Minimum Generation Emergency Credit is calculated, subtract the Resource’s Economic Minimum Limit from its Real-Time Generation Obligation and then multiply the result by the Market Participant’s Ownership Share in the

Resource. The sum of the results of such calculations shall be that Market Participant's Exempt Real-Time Generation Obligation.

(2) Subtract the sum of the Exempt Real-Time Generation Obligations for all Market Participants from the total Real-Time Generation Obligation of all Market Participants at Locations within the Reliability Region(s) for which a Minimum Generation Emergency was declared.

(3) Subtract the Market Participant's Exempt Real-Time Generation Obligation, as calculated in step (1) above, from its total Real-Time Generation Obligation within the Reliability Region(s) for which a Minimum Generation Emergency was declared, and then divide that result by the result in step (2).

(4) Multiply the total Minimum Generation Emergency Credit by the result in step (3). This result is the Market Participant's Minimum Generation Emergency Charge.

III.F.3.2. Calculations

III.F.3.2.1 Day-Ahead NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total Day-Ahead NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead NCPC Credits, as previously calculated, for generating Resources, Postured generators (non-VAR) and Dispatchable Asset Related Demand (pumps only).

III.F.3.2.2 Local Second Contingency Protection Resource NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participants' Day-Ahead Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.3 VAR related NCPC Cost, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the total VAR related NCPC cost associated with the Day-Ahead Energy Market by summing all Market Participant's Day-Ahead VAR credits.

III.F.3.2.4 NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the NCPC Charges for the Day-Ahead Energy Market by allocating the total economic NCPC cost for the Day-Ahead Energy Market to each Market Participant based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations (including the Hub). For each External Node, if there are any Day-Ahead External Transaction purchase credits for each External Transaction purchase or Increment Offer cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Load Obligations at the External Node. If there are any Day-Ahead External Transaction sale credits for each External Transaction sale or Decrement Bid cleared in each hour, they are allocated and charged pro-rata to the hourly Day-Ahead Generation Obligations at the External Node.

III.F.3.2.5 Local Second Contingency Protection Resource NCPC Charges, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Day-Ahead Energy Market for each affected Reliability Region by allocating the total Local Second Contingency Protection Resource NCPC cost for the Day-Ahead Energy Market for each affected Reliability Region to each Market Participant within each affected Reliability Region based on the Market Participant's pro-rata daily share of the sum of Day-Ahead Load Obligations over all Locations within the affected Reliability Region (not including the Hub).

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Day-Ahead Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.F.3.2.6 VAR Charges, Day-Ahead Energy Market, Day-Ahead Energy Market.

The ISO calculates for each Operating Day the VAR Charges for the Day-Ahead Energy Market by allocating the sum of the total VAR related NCPC cost for the Day-Ahead Energy Market to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.7 Non-Synchronous Condenser related Economic NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total non-Synchronous Condenser related economic NCPC cost associated with the Real-Time Energy Market by summing all Market Participant's Real-Time NCPC Credits not related to Synchronous Condensers, as previously calculated, and the total Synchronous Condenser related NCPC cost (non-VAR related) associated with the Real-Time Energy Market by summing all Market Participants' non-VAR related Real-Time Synchronous Condenser related NCPC Credits for generating Resources, pool scheduled External Transaction purchases, pool- scheduled External Transaction sales and Dispatchable Asset Related Demand Resources (pumps only), cancelled Pool-Scheduled Resources excluding Resources Postured for reliability.

III.F.3.2.8 Local Second Contingency Protection Resource NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total Local Second Contingency Protection Resource NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time Local Second Contingency Protection Resource NCPC Credits.

III.F.3.2.9 SCR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total SCR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time SCR NCPC Credits.

III.F.3.2.10 VAR NCPC Cost, Real-Time Energy Market.

The ISO calculates for each Operating Day the total VAR NCPC cost associated with the Real-Time Energy Market by summing all Market Participants' Real-Time VAR credits including VAR credits associated with Synchronous Condensers and Postured generating Resources.

III.F.3.2.11 [Reserved.]

III.F.3.2.12 Real-Time Load Obligation Deviation.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1) by summing the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub).

III.F.3.2.13 [Reserved.]

III.F.3.2.14 Real-Time Generation Obligation Deviation at External Nodes.

The ISO calculates for each hour of the Operating Day each Market Participant's Real-Time Generation Obligation Deviation at External Nodes by summing the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

III.F.3.2.15 Other.

The ISO calculates for each Operating Day the non-Postured non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related, non-Regulation and non-SCR related economic NCPC Charges for the Real-Time Energy Market for each Market Participant by allocating the total Real-Time non-Synchronous Condenser related, Synchronous Condenser related, non-Local Second Contingency Protection Resource related and non-SCR related NCPC cost to each Market Participant based on their daily pro-rata share of the daily sum of the following hourly Real-Time deviations:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resources Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following ISO Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following ISO Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – Cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation (as adjusted in accordance with Section III.F.3.1)

[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation

Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.
[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

plus,

(g) the absolute value of the total over all Locations of the Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.2.16 Local Second Contingency Protection Resource NCPC Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the Local Second Contingency Protection Resource NCPC Charges for the Real-Time Energy Market for each Market Participant within each affected Reliability Region by allocating the total Real-Time Local Second Contingency Protection Resource NCPC cost to each Market Participant within each affected Reliability Region based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating Local Second Contingency Protection Resource NCPC Charges in the Real-Time Energy Market. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(a) For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, for hours in which there is a Local Second Contingency Protection Resource NCPC cost (as calculated in Section III.F.3.2.8) and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of proportional shares of Real-Time Load Obligations as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The proportionate share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-37 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
1385 Cable External Node	Northport-Norwalk Harbor (1385 Line)	Connecticut	100% to Connecticut
Cross Sound Cable External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(b) For each month, the ISO performs an evaluation of total Real-Time Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph b, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only) above its Minimum Consumption Limit.

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

III.F.3.2.17 VAR Charges, Real-Time Energy Market.
The ISO calculates for each Operating Day the VAR Charges (including Synchronous Condensers) associated with the Real-Time Energy Market by allocating the total Real-Time VAR cost to each Market Participant based on Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.F.3.2.18 SCR Charges, Real-Time Energy Market.

The ISO calculates for each Operating Day the SCR Charges associated with the Real-Time Energy Market by charging the total Real-Time SCR cost to the appropriate entities based on Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	**Docket No. ER12- -000**
	)	

JOINT TESTIMONY OF MATTHEW WHITE AND JANINE DOMBROWSKI

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Matthew White. I am the Senior Economist for ISO New England Inc., One Sullivan Road, Holyoke, Massachusetts 01040-2841.

A: My name is Janine Dombrowski. I am Principal Market Design Analyst for ISO New England Inc., One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Please describe your work experience and educational background.

A: *Dr. White:* Prior to joining the ISO, I held faculty appointments at the University of Pennsylvania's Wharton School of Finance and Commerce (2002-2009) and Stanford University's Graduate School of Business (1995-2001). At these institutions I conducted research on electricity demand, pricing, and market design, and taught graduate-level courses in economics and decision analysis. My public service includes appointments as a senior staff economist at the Federal Energy Regulatory Commission, Office of Energy Policy and Innovation (2009-

2010) and the Federal Trade Commission, Bureau of Economics (2001-2002). My research studies have been published in peer-reviewed economics journals, and I have served as a referee and evaluator for the National Science Foundation and over twenty-five journals spanning economics, engineering, and political science. I received a M.S. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

Dr. Dombrowski: I have a Bachelor of Science degree in Physics and a Ph.D. in Resource Economics from the University of Massachusetts. I have been with the ISO since 2001. Between 2001 and 2007, I held several roles in the Market Monitoring department, including responsibility for evaluating new markets and implementing the market monitoring provisions for the Forward Capacity Market. I have worked in Market Development since July 2007, supporting market design and implementation. During this time I have led the development of design solutions, providing design options and coordinating changes with ISO business owners and New England market participants. I led the effort to develop the rule changes that are the subject of this proceeding.

II. PURPOSE, SCOPE AND BACKGROUND OF DIRECT TESTIMONY

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to provide factual support to the ISO's filing of a series of tariff revisions to implement enhanced external transaction scheduling procedures on certain interfaces between New England and New York. This testimony explains the market inefficiencies with the current transaction scheduling process, the causes of these inefficiencies and the financial cost of these inefficiencies, the modified scheduling process, referred to as Coordinated Transaction Scheduling, and how the modified process addresses the identified inefficiencies.

III. OVERVIEW AND RATIONALE FOR COORDINATED TRANSACTION SCHEDULING

Q: Why is the ISO proposing to implement Coordinated Transaction Scheduling at this time?

A: The External Market Monitor, in conjunction with the ISO, has identified inefficiencies in the way energy is imported and exported between New England and New York. These inefficiencies, and their adverse impact on the combined cost of operating the power systems in the two regions, are documented in detail in Sections II.A and II.B of the joint *ISO New England Inc. and New York Independent System Operator, Inc. White Paper* on *Inter-Regional Interchange Scheduling: Analysis and Options* (January 5, 2011) (the "Joint ISO White Paper"). A copy of the Joint ISO White Paper is included with the filing materials. Dr. White was a principal author of the Joint ISO White Paper.

Q: Please summarize your findings regarding these inefficiencies and their impact on the cost of operating the regions' power systems.

A: There are two inefficiencies. First, transmission operational data indicate that there is significant under-utilized transmission capacity between New York and New England (*cf.*, Figure II-1 in the Joint ISO White Paper). This under-utilization is taking place during times when there is sufficient transmission capacity to move additional power from the region with the lower Locational Marginal Price ("LMP") to the region with the higher LMP (*cf.*, Figure II-2(a) and II-2(b) in the Joint ISO White Paper). That means the combined cost of operating the power systems in the two regions would be lower if the existing transmission capacity between them was used to further displace higher-cost generation in one region with lower-cost generation in the other region.

Q: What is the second inefficiency?

A: The second inefficiency is that current scheduling procedures often result in net interchange schedules from the *higher* price region to the *lower* price region. This phenomenon is known as *counter-intuitive flow*, because participants' economic interests would be expected to produce interchange schedules from the lower-price to the higher-price region. Counter-intuitive flow means that the interchange schedule is causing the exporting region to increase production from high-cost generation at the margin, and the importing region to decrease production from low-cost generation at the margin. This economically perverse outcome raises the total costs of serving demand, relative to a level of flows that equalized the marginal cost of generation in each region. The ISO is proposing to implement Coordinated Transaction Scheduling to reduce these inefficiencies.

Q: Has the ISO quantified the costs of these inefficiencies, and correspondingly the benefits of reducing them?

A: Yes. The ISO and the NYISO requested that New England's External Market Monitor, Potomac Economics, analyze each ISO's market data to quantify these costs, and to estimate the benefits of Coordinated Transaction Scheduling. For each year from 2008 to 2010, the External Market Monitor's analysis estimated the impact on the two regions' combined total production costs had the Coordinated Transaction Scheduling system been in place during those periods. The analysis also examined the changes in average LMPs in each region, and changes in load's energy market expenditures, relative to the status quo. The External Market Monitor presented its findings to New England stakeholders on January 21, 2011. A copy of its presentation, *Benefits of Coordinating the Interchange Between New York and New England* ("Potomac Economics Study"), is included with the filing materials. [1]

Q: Can you summarize the External Market Monitor's study methodology?

A: Yes. The External Market Monitor used market offers from generation and demand data in each region from 2008 through 2010 to simulate the hourly generation re-dispatch that would converge prices, or bind the interface if that

[1] Note that the External Market Monitor's presentation compared the benefits of implementing two alternative proposals for modifying the external transaction scheduling procedures. The proposal referred to as "Interface Bidding" is the Coordinated Transaction Scheduling procedures that the ISO is filing with the Commission in this series of tariff revisions. The two regions' evaluation of the second proposal, Tie Optimization, is addressed in the Transmittal Letter.

occurs first, between the two regions. It then calculated both the change in production costs associated with this re-dispatch and the estimated reduction in energy expenditures by load for the two regions.

The estimated cumulative reduction in total production costs over the three-year study period resulting from more efficient interface scheduling under Coordinated Transaction Scheduling ranges from $26 million to $34 million dollars for the two regions combined. The range of values reflects estimated results under a range of assumptions about the performance of the proposed scheduling system. The annual figures vary modestly from year to year, being higher when fuel prices are high, as occurred in 2008, and lower when fuel costs decline, as occurred in 2009.

The estimated cumulative reduction in total energy expenditures by load over the three-year study period under Coordinated Transaction Scheduling ranges from $387 million to $417 million. Of this total reduction, the share accruing to load in New England ranges from $183 million to $219 million (*Cf.*, Potomac Economics Study, pp. 8-9).

Q: Did the study indicate average LMPs would be lower in both regions? Why?

A. Yes. The External Market Monitor's analysis found that both regions' LMPs would be lower on an annual average basis. There are two factors that explain why. The first factor is that, in any particular hour, the lower-cost ISO tends to be operating on a flat portion of its aggregate supply curve, and the higher-cost ISO tends to be operating on a steeper portion of its aggregate supply curve. Increasing the amount of power flowing from the low-cost to high-cost region therefore tends to drop the LMP in the high-cost region a lot, but raise the price in the low-cost region by less. The second factor is that each region has lower costs with similar frequency over the course of the year. For example, across the primary external interface between the two regions in 2009, New England had a lower LMP approximately half of the hours annually, and New York the other half of the hours annually (*cf.*, Figure II-6 in the Joint ISO White Paper).

As a result of these two factors, within each region the decrease in LMP when more efficient scheduling increases imports exceeds (in magnitude) the increase in LMP when more efficient scheduling increases exports, on an annual average basis (*cf.*, Potomac Economics Study, p. 10). Thus each region's average LMP falls overall. This explains the External Market Monitor's finding that total annual energy expenditures by load would be lower in both New York and New England, in each year studied, with more efficient interchange scheduling under Coordinated Transaction Scheduling.

Q: Why is the reduction in energy expenditures by load much larger than the reduction in total production costs by generation?

A: If improved interchange displaces a higher-cost generator in one region with a lower-cost generator in the other region, the two regions' combined total production costs falls by an amount proportional to the quantity of generation displaced. However, the resulting impact on LMPs applies to all energy in each market, not simply to the quantity of generation displaced. Because the quantity of energy consumed by load in each market is substantially larger than the amount of generation displaced by improved interface scheduling, the impact on expenditures by load is substantially larger than the impact on total production costs.

Q: Did the ISOs examine the root causes of these inefficiencies?

A: Yes. The ISOs established that there are three root causes of the identified inefficiencies in the scheduling of the interfaces. In summary, they are:

> *Latency Delay:* The time delay between when the external transactions are scheduled and when power flows, during which time system conditions and LMPs may change in each region;
>
> *Non-economic Clearing:* The ISOs make decisions about which import and export schedule requests to accept without economic coordination, which can produce inefficient interchange schedules between regions; and
>
> *Cross-Border Transaction Costs:* The fees and charges levied by each ISO on external transactions serve as a disincentive to engage in cost-reducing trade between regions, impeding price convergence and raising total system production costs.

These causes are explained in detail in Section II.C of the Joint ISO White Paper.

Q: Please explain further what the first root cause, latency delay, is and why it occurs.

A: "Latency" is the time delay between when (1) an ISO accepts a market participant's external transaction request, and (2) the transaction's scheduled interchange between regions is complete. Under the current inter-regional trading system, the latency delay for external transactions between New England and New York is nearly two hours. This delay results from several factors, including the minimum one-hour duration of external transactions today, and the processing time required by the ISOs to exchange information about independently submitted external transaction requests and their resulting upcoming physical power flow changes between areas. In practice, a "real-time" external transaction request must be submitted by a market participant to the ISO no later than 60 minutes prior to the hour for which the participant requests that delivery commence; the ISO determines whether or not to accept a "real-time" external transaction about forty-five minutes before the delivery hour; and the scheduled transaction quantity remains fixed for the full delivery hour. Note that although this combination of hourly lead-time and the hourly duration-time is commonly referred to as an "hourly scheduling" system, the latency delay is almost double that.

Q: What are the consequences of latency delay?

A: Latency delay causes excess costs for the system as a whole. Power system conditions can change from minute to minute, altering each ISO's LMPs and marginal generation cost. That can make an external transaction that appeared economic when scheduled nearly an hour earlier uneconomic during the delivery hour. This has three distinct adverse consequences, for individual market participants and for the regions as a whole:

- *Transmission under-utilization.* If the importing region's LMP rises relative to the exporting region's LMP after all external transactions are scheduled, imports are more valuable in real-time than the market anticipated when interchange schedules were set an hour earlier. Even though power is flowing in the "right" direction to lower the regions' combined total production costs, *not enough* power is flowing the right direction to minimize total production costs. A graphical illustration of this situation is depicted in Figure II-3 in the Joint ISO White Paper.

- *Counter-intuitive flow*. If the importing region's LMP falls relative to the exporting region's LMP after external transactions are scheduled, counter-intuitive flows may result. That inefficiently displaces low-cost generation at the margin in one ISO with high-cost generation at the margin in the other ISO, *increasing* total costs for the two regions relative to the efficient level of interchange. A graphical illustration of this situation is depicted in Figure II-4 of the Joint ISO White Paper.

- *Unnecessary economic risk*. From the perspective of a market participant submitting an external transaction, the latency problem creates financial risk. If the price difference between regions changes after a participant's external transaction is scheduled, the market participant can end up "buying high and selling low," losing money on each megawatt scheduled.

This risk poses a deterrent to submitting external transactions in the first place, exacerbating the transmission under-utilization problem.

Q: Please explain the second root cause of inefficient interchange schedules, termed "non-economic clearing."

A: Under the current system, market participants submit separate external transaction requests to each ISO. For instance, an offer to buy, or export, from New England is submitted only to the ISO, and the matching offer to sell, or import, into New York is submitted only to the NYISO. There is no economic coordination between the ISOs when they evaluate these offers and use them to determine the net interchange schedule. This absence of economic coordination when external transaction requests are accepted produces inefficient interchange schedules, and raises total system costs.

Q: How exactly does this produce inefficient interchange schedules and raise total system costs?

A: In an economically sound market design, an external transaction should be accepted and incorporated into the net interchange schedule if condition (A) is true:

(A) The importing region's expected LMP exceeds the exporting region's expected LMP.

Note this assumes available transmission capacity at the time the external transactions are scheduled. Condition (A) implies that low-cost generation in one region displaces high-cost generation in the other region, lowering total production costs. However, the current external transaction system does not verify condition (A). Instead, it checks two different conditions:

(B) The offer to buy (export) submitted to the exporting ISO exceeds the exporting region's expected LMP;

(C) The offer to sell (import) submitted to the importing ISO is less than the importing region's expected LMP.

The ISO receiving the export-side schedule request checks (B), and—separately—the ISO receiving the import-side schedule request checks (C). If both conditions are satisfied (known as "check out"), then the external request is scheduled by both ISOs and increments the net interchange schedule for the requested delivery hour.

The problem with this is that the two independent checks to see if the offer to export exceeds the exporting region's expected LMP (*i.e.*, condition (B)), and the check to see if the offer to import is less than the importing region's expected LMP (*i.e.*, condition (C)), do not guarantee that the importing region's expected LMP exceeds the exporting region's expected LMP (*i.e.*, condition (A)). Scheduled transactions that do not satisfy condition (A) can actually *raise* total system costs.

As a typical example, this inefficient scheduling may occur when a market participant submits a price-based bid on the NYISO side of the border, and a "fixed bid" on the ISO-NE side of the border. (A "fixed bid" is an offer to pay up to $1000 per MWh to export, or to accept any price above zero to import). Any such bid-pair that clears on the NYISO side will also clear in ISO-NE, even if condition (A) fails.

Q: Why does that raise total system costs?

A: If condition (A) is not satisfied, then a participant's offer to buy (export) from one region may clear at a *higher* price, while the offer to sell (import) in the other region clears at a *lower* price. That means the participant's transaction raises total costs for the system as a whole: High-cost generation in the exporting region is displacing low-cost generation in the importing region.

Q: Does the ISO's data indicate that power is scheduled to flow from the higher-price area to the lower-price area, violating condition (A)? How often does this occur?

A: Yes. Data studied by the two ISOs indicate that non-economic clearing is fairly prevalent. Data for all hours from July through December 2009 indicate that the ISOs are scheduling power from the high-to-low cost region (at the margin), raising expected total production costs, 44 percent of the time. (*Cf.*, p. II-18 and Figures II-8(a) and II-8(b) in the Joint ISO White Paper). This is not because of latency; these data are based on the ISOs' expected LMPs in each region as of the time the ISOs set the net interchange schedule, which occurs approximately 45 minutes in advance.

In addition, the data further indicate that even when the net interchange schedule is in the economically correct direction (at the margin), too little power is being scheduled to converge the LMPs most of these hours. That means total system costs for the ISOs are unnecessarily high: In these hours, trade fails to displace high-cost generation with additional lower-cost generation available from the exporting region. This situation is also indicated in the data shown in Figure II-8(a) and II-8(b) of the Joint ISO White Paper.

It is important to note that these situations are evident in data based on expected system conditions as of the time the interface is scheduled. That means that, if the ISO and the NYISO had a coordinated exchange of economic information at the time external transactions are scheduled, they would have been able to see that the current interchange scheduling system produced an inefficient net interface schedule. However, today's inter-regional trading system does not conduct an exchange of economic information about external transactions, so these inefficiencies are evident only in after-the-fact analyses of interchange schedule results.

Q. Please explain the third root cause of inefficient interchange schedules, cross-border transaction costs.

A. The third root cause of inefficient interchange schedules are the transaction costs that market participants pay when they schedule external transactions. Both New

England and New York impose a number of different fees and charges on external transactions. For example, ISO-NE's tariff allocates a portion of total Net Commitment Period Compensation ("NCPC") costs (informally called 'uplift' charges) to real-time external transactions. These charges can be highly variable from day to day, are difficult to predict in advance, and there is no practical means for a market participant to hedge against them.

The allocation of these costs and other ISO fees to external transactions serves as an economic impediment to trade between regions. Economic principles imply these fees will be factored into the bids of the market participants who submit external transactions. Specifically, to cover the expected fees and charges levied by the ISOs, a market participant should submit an external transaction request only if the expected price difference between regions exceeds the expected fees and charges. This behavior prevents price convergence between regions, even if the first and second root causes are eliminated; the absence of price convergence adversely impacts the two regions' combined total production costs. System costs will be higher than necessary because the existing transmission capacity between regions will tend to be under-utilized, relative to external transaction volumes, if there were no transaction fees and charges. In economic terms, transaction fees on external transactions act like a "tax" that deters trade and distorts total system production costs upward.

Q: If ISO fees and charges are eliminated for external transactions under the Coordinated Transaction Scheduling system, will these same fees and charges have to be reallocated to other market participants? Is that likely to produce net benefit to load overall?

A: Yes, and yes. ISO fees and charges are allocated in a number of different ways. The current system allocates them in a way that prevents price convergence between regions, which is particularly inefficient. It means one region will tend to have higher-cost generation on the margin when lower-cost power is available in the adjacent region, with transmission capacity to spare between them, yet market participants will choose not to schedule additional interchange between the regions. In simple terms, allocating fees and charges in this way impedes the effectiveness of competition among power generators in the broader inter-regional power system that would lower the cost of serving demand.

While the allocation of ISO fees and charges to external transactions would seem to “save” load and other market participants from paying these fees, eliminating the allocation to external transactions may lower load and other participants’ total costs overall. An example illustrates why. A fee of $5 per MWh on 1000 MW of external transactions in a particular hour means other market participants avoided paying that $5,000 in ISO fees. The $5 per MWh fee can be expected to result in an LMP difference between regions of at least $5 per MWh, because participants scheduling external transactions must cover the cost of the fee by selling power in one ISO's real-time energy market at a price at least $5 per MWh higher than they paid to buy it in the other ISO's market.

In contrast, an efficient inter-regional interchange system would converge prices between regions. That would reduce the regions' price difference by $5 per MWh in this example. Now consider the value to load of converging prices by that $5 per MWh. As noted previously in connection with the Potomac Economics Study (described in Part III), an increase in scheduled interchange that converges prices tends to lower the importing region's LMP by more (in magnitude) than the exporting region's LMP rises. For example, the LMP may fall by $3 per MWh in the importing region, and rise by $2 per MWh in the exporting region, to eliminate the $5 per MWh price spread between regions. Assuming, to keep this example simple, that both regions have equal loads of (say) 20 GW at the time, the *net* savings to load from eliminating the external transaction fees in this scenario would be at least $15,000 for that hour (20 GW × ($3 – $2)/MWh, less the $5,000 in re-allocated fees). In sum, even if the $5 per MWh fee was reallocated to only load, the $15,000 net benefit to load is three times larger than the additional $5,000 in fees they are allocated.

Although this is a simple example, it illustrates a general economic principle. When fees and charges are allocated in an economically inefficient way, there is usually another way to allocate such fees and charges that creates greater benefit than the reallocated costs. The additional benefit is created because changing the inefficient fee allocation reduces a larger market distortion. In this context, the larger distortion is the excessive cost of operating the two regions' power systems when the transmission lines between them are under-utilized.

Q: Let's turn now to how Coordinated Transaction Scheduling addresses the causes of inefficient interchange scheduling. Will implementation address each of the three root causes?

A: Yes. Coordinated Transaction Scheduling addresses each of the three identified inefficiencies. First, it uses more frequent interface scheduling, reducing latency delay. Second, it uses a simplified bid format and a clearing rule that coordinates economic clearing of external transactions between the two ISOs. Third, it eliminates the transaction fees from external transactions at interfaces subject to Coordinated Transaction Scheduling.

Q: Please elaborate on the changes to interchange scheduling frequency under Coordinated Transaction Scheduling.

A: To minimize latency delays, it is desirable to set the net interchange schedule as close to real-time as possible, and to update it as frequently as system conditions change. Currently, external transactions are scheduled a full hour before the delivery hour, and remain fixed for the full delivery hour. Under Coordinated Transaction Scheduling, the ISOs will update the net interface schedule across each AC interface between New England and New York for which Coordinated

Transaction Scheduling is implemented every 15 minutes. The net interface schedule is fixed for 15 minutes between each update. Within each 15-minute interval, each ISO will perform its internal dispatch as it does today.

The choice of 15-minute intervals is determined by current technology and operational considerations. With additional advances in technology, it may be possible to further shorten this interval. The key technological and operational constraint is that interface scheduling requires "pre-scheduling" runs of the unit dispatch system to be performed by the ISOs, and an exchange of economic solution and external transaction information between ISOs after these pre-scheduling runs. The resulting coordinated interface schedule is then incorporated into each ISO's internal dispatch solutions during the 15-minute interval to which the interchange schedule applies.

Q: Please explain how Coordinated Transaction Scheduling uses a simplified bid format to perform economic clearing of real-time external transactions.

A: As explained above, under the current system, there is no economic coordination between the ISOs when the net interchange schedule is determined. This produces inefficient interchange schedules, and raises total system costs. Under Coordinated Transaction Scheduling, a participant may submit a single real-time external transaction bid that is used by both ISOs. The two ISOs apply a coordinated clearing process that determines the net interchange schedule.

Specifically, under Coordinated Transaction Scheduling, a real-time external transaction is accepted if the offered price is less than (or equal to) the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled. This is an economically-coordinated clearing process that will tend to set the net interchange to flow from the region with lower prices to the region with higher prices. Doing so improves economic efficiency by displacing higher-cost generation in one region with lower-cost generation in the other, which lowers the combined costs of operating the two regions' power systems.

Q: Please summarize the fees, charges, and credits that are being changed to eliminate the inefficiencies caused by cross-border transaction costs.

A: For external transactions at interfaces under to Coordinated Transaction Scheduling, the ISO will no longer apply certain fees, charges, and associated credits. These include fees, charges, and credits associated with the costs of uplift (*i.e.*, NCPC), emergency energy purchases and sales, purchases to maintain minimum flow, costs for regulation service, and credits and charges for the difference between the actual and scheduled energy flows.

Note that the ISO is not eliminating these fees, charges, and credits categorically; rather, the aggregate amounts of these fees, charges, and credits will continue to be allocated to market participants' transactions that remain eligible for them. In this sense, the dollar amount of the affected fees, charges, and credits will be reallocated to market participants' other transactions that are presently allocated these amounts.

The ISO's proposed changes to its fees, charges, and credits under Coordinated Transaction Scheduling are narrowly focused on exempting affected external transactions in an effort to eliminate cross-border transaction costs that inefficiently distort trade between regions and raise the total costs of operating the power systems. As explained previously, it is anticipated that the reallocation of fees and charges as part of Coordinated Transaction Scheduling will lower total system costs overall, creating a greater benefit for the region than the reallocated costs.

Q: Is the ISO seeking to eliminate these fees, charges, and credits in a similar, reciprocal way with the NYISO?

A: Yes. As discussed in detail in the Section II.C of the Joint ISO White Paper, under Coordinated Transaction Scheduling both the ISO and the NYISO are proposing to eliminate certain fees and charges that create inefficient market "seams" between regions.

Q: Is there precedent for reducing market "seams" this way?

A: Yes. In 2004, in response to a Commission order designed to reduce "seams" between New York and New England, the ISO filed to eliminate certain Through-and-Out OATT charges on external transactions between New England and New York. That was also done on a reciprocal basis with the NYISO.

IV. TARIFF REVISIONS TO IMPLEMENT COORDINATED TRANSACTION SCHEDULING.

Q: Please summarize the primary components of Coordinated Transaction Scheduling.

A: As noted above, Coordinated Transaction Scheduling uses a simplified bid format, called an "Interface Bid," and coordinated economic clearing of real-time external transactions by the ISO and the NYISO. Coordinated Transaction Scheduling also employs higher frequency scheduling of the external interface between New England and New York, and eliminates certain charges and credits on external transactions that deter trade.

The tariff changes to enable these features may be summarized by the following categories:

A. Changes to Real-Time External Transaction offers;
B. Changes to Real-Time External Transaction clearing;
C. Changes to Real-Time External Transaction settlement;
D. Changes to External Interface congestion;
E. Changes to Fee, Credit, and Charge Eligibility for External Transactions.

Q: Is the ISO proposing any other changes to the ISO Tariff as part of the Coordinated Transaction Scheduling project?

A: Yes. The ISO is proposing revisions to the Forward Capacity Market rules, in order to address how certain features of Coordinated Transaction Scheduling impact the rights and obligations of import capacity resources.

In addition, the proposed tariff revisions include a procedure for evaluating the effectiveness of Coordinated Transaction Scheduling at the one and two year mark after implementation, as well as a procedure for modifying Coordinated Transaction Scheduling based on that evaluation or, in the alternative, replacing Coordinated Transaction Scheduling with a scheduling process commonly referred to as "Tie Optimization."

A. REAL-TIME EXTERNAL TRANSACTION BIDS

Q: Please explain the Interface Bid format for real-time external transactions.

A: In economic terms, an Interface Bid is a unified transaction to buy and sell power simultaneously on each side of an external interface. This unified bid structure is designed to resolve one of the three root causes of the existing system's inefficiencies: The non-economic clearing problem, described previously.

Mechanically, an Interface Bid consists of four components: A price, a direction, a quantity, and the time period to which the bid applies. The price indicates the minimum expected price difference between the two regions that the participant is willing to accept. The direction indicates in which region the participant wants to buy, and in which it wants to sell. The quantity indicates how many megawatts the participant is willing to transact. The time period specifies which one, or more, 15-minute scheduling interval(s) to which the bid applies.

Q: Are participants permitted to submit multiple Interface Bids and at different prices?

A. Yes. A participant may submit more than one Interface Bid for the same time periods, or for overlapping time periods. Such bids may have different prices, quantities, and directions.

Q: Are interface bids to be submitted separately to each ISO?

A: No. To improve bid submission and processing procedures for participants, the ISO and NYISO plan to develop a common bid submission platform. The platform is intended to provide a one-stop, automated bid submission and validation tool for Interface Bids under Coordinating Transaction Scheduling. The information submitted by a market participant to this common platform will be accessible to, and used by, both ISOs to coordinate clearing of the real-time external transaction bids that determine the net interface schedule.

The common submission platform is expected to eliminate 'failure to check-out' outcomes that occur when the real-time external transaction data a market participant submits independently to each ISO do not match each other exactly. Such problems are an inefficient source of risk for market participants submitting external transaction requests today.

Q: When will Interface Bids be submitted?

A: Current rules require real-time external transaction requests to be submitted no later than 75 minutes before the delivery hour on the New York side, and no later than 60 minutes before the delivery hour on the New England side. These submission deadlines need to become a common point in time, since market participants will now submit a single bid. To do so, the ISO will require the transaction submission deadline for Interface Bids under Coordinated Transaction Scheduling to be no later than 75 minutes in advance of the start of the delivery period to which the interface bid applies. This is to accommodate the look-ahead information needs of the ISOs' dispatch and commitment systems, which on the New York side assess changes in physical interface schedules 75 minutes ahead of time.

B. REAL-TIME EXTERNAL TRANSACTION CLEARING

Q: Please explain the changes to the manner in which Real-Time External Transactions are cleared under Coordinated Transaction Scheduling.

A: Like the current external transaction system, under Coordinated Transaction Scheduling the ISOs use information from two sets of market-based offers to determine the real-time net interchange schedule. The two sets are (1) participants' real-time external transaction bids, and (2) the as-bid costs of generators and other physical supply resources in each region. However, the process by which this information is used to clear a real-time external transaction request differs between Coordinated Transaction Scheduling and the existing inter-regional system.

Under today's external transaction scheduling mechanisms, market participants submit separate external transaction requests to each ISO (*e.g.*, an offer to buy, or export, from ISO-NE is submitted only to ISO-NE, and the matching offer to sell, or import, in NYISO is submitted only to NYISO). There is no economic coordination between the ISOs when they set the net interchange schedule.

In contrast, under Coordinated Transaction Scheduling, the two ISOs apply a coordinated process that determines the net interchange schedule. Specifically, an Interface Bid will clear if the offered price is less than the expected LMP difference across the external interface in the requested direction, as of the time the interface is scheduled.

The total aggregate quantity of cleared Interface Bids for a particular 15-minute time interval shall determine the net interface schedule for that time interval. Note that the quantity of Interface Bids that may clear in a particular direction may be limited during that time interval by the transmission capability of the interface, interface ramp limits, or other reliability-based operating limits. In such circumstances, Coordinated Transaction Scheduling will accept the lowest-priced set of Interface Bids for which the bids' associated total quantity (in MW) satisfies the applicable operating limit.

Q: This appears to require greater communication and coordination than today between the two ISOs to evaluate real-time external transactions and determine the net interface schedule. Is that correct?

A: Yes. The two ISOs will perform a coordinated evaluation of whether each Interface Bid is expected to be "economic," in the sense of the clearing rule described in the previous question. By doing so, the quantity (in megawatts) of all external transaction requests that clear for an upcoming 15-minute interval will produce a net interface schedule that tends to converge prices between regions and to produce a scheduled physical power flow from the lower-cost region to the higher-cost region.

In effect, Coordinated Transaction Scheduling uses Interface Bids as the market-based device with which the ISOs determine the real-time net interchange schedule between New England and New York in an economically coordinated way, using the best information available to the two ISOs as of the time the interface is scheduled. The purpose of this economic coordination is to resolve the "non-economic clearing" root cause of inefficient interchange schedules, described previously.

Q: How frequently will clearing be performed?

A: As noted earlier, the current inter-regional trading system uses an hourly external transactions scheduling system. To reduce latency delay under Coordinated Transaction Scheduling, Interface Bids will be cleared every 15 minutes. The net interchange schedule will be updated at the same frequency.

C. REAL-TIME EXTERNAL TRANSACTION SETTLEMENT

Q: How does a participant with a cleared Interface Bid settle?

A. The ISO and the NYISO will settle each respective 'side' of a cleared Interface Bid separately, at their respective real-time prices for the time period for which the transaction clears. For example, if an Interface Bid is cleared in the direction of an export from New England and an import into New York, ISO-NE will settle the export side of this transaction and the NYISO will settle the import side of this transaction. Continuing the example, this means the ISO will charge (for an export) the market participants who cleared each Interface Bid an amount equal to the cleared Interface Bid quantity times the real-time LMP associated with the external interface across which the transaction is scheduled. The NYISO would handle settlement of the import side of the transaction, in this example.

If the Interface Bid was cleared in a different direction, the same process applies but with the ISO crediting the transaction as an import, and the NYISO debiting (that is, charging) the transaction as an export.

Q: Please explain the logic of this settlement approach from a pool-level settlement perspective.

A. Suppose, for simplicity, that the ISOs clear a single interface bid from one area to the other. As usual, load on the import side (whichever region that may be) pays the LMP at its locations. In the importing region, internal generation is paid the same LMP. However, there is less total generation than internal load in the importing ISO, so the importing ISO receives more revenue from internal load than it pays to its internal generation. This revenue is paid to the market participant whose Interface Bid cleared, as a credit for the imported power. In this sense, participants with accepted Interface Bids are selling power to the importing region's load, at a lower expected cost than the price of internal generation.

The exporting region's settlement logic is symmetric. All generation is paid the LMP at its location, as usual. However, in the exporting ISO there is more generation than internal load. The market participant whose Interface Bid cleared is charged for the difference: It pays the exporting region's LMP for each MW cleared at the interface. In this sense, participants with accepted Interface Bids are buying power supplied by the exporting region's generation.

Of course, like the existing settlement system, there are additional settlement elements that arise due to congestion and marginal losses. LMPs at the external interface will not always equal internal node LMPs, because the transmission network may be congested. Nevertheless, in such situations the pool-level settlements logic summarized above carries forward in a similar way.

Q: Will the 15-minute interval for clearing Interface Bids also apply to transaction settlement?

A: Yes. A market participant's interface bid will be evaluated on a 15-minute basis, and if accepted (*i.e.*, cleared) will be settled on a 15-minute basis.

Q: Please elaborate.

A. The ISO calculates real-time LMPs every 5 minutes. Under Coordinated Transaction Scheduling, if a participant's real-time external transaction clears for only one 15-minute period, the ISO will settle its side of the transaction at an average of the ISO's three consecutive 5-minute real-time LMPs during that period. Similarly, if a transaction clears for two consecutive 15-minute periods, it will settle at an average of the 5-minute real-time LMPs during that 30-minute period. Note that this is similar to, but more frequent than, the way an hourly real-time external transaction settles today: The ISO's existing hourly scheduling system settles real-time external transactions at an average of the twelve 5-minute real-time LMPs during the transaction's delivery hour.

Q: Why is the ISO changing settlement of real-time external transactions under Coordinated Transaction Scheduling to a 15-minute basis? Is it important

for that to be aligned with the 15-minute frequency of the net interchange schedule?

A. Yes. There is a sound economic rationale for aligning the period when a participant's transaction clears with its settlement. For example, imagine a market participant clears a transaction under CTS into New England for the first two 15-minute periods in an hour, with an interface bid of $2/MWh in each period. Suppose the applicable real-time prices during each period are $48/MWh in New York and $50/MWh in New England. The participant receives, on net, $2 for each MWh that it clears.

Consider now the problems that arise if, contrary to design, the settlement period did *not* match the Interface Bid transaction period. Assume that for the second 30 minutes of this hour, the real-time LMP in New England fell to $40/MWh. The hourly LMP in New England would be ½ ($50 + $40) = $45. If the market participant was credited at New England's *hourly* LMP—instead of the LMP when the transaction flowed—ISO-NE would credit the participant only $45/MWh. Assuming New York's price remains $48, the participant now suffers a net *loss*: $45 – $48 = $–3 for each MWh it cleared.

The point of this example is important: The participant imported power from the lower-cost region into the higher-cost region for 30 minutes, and produced an efficiency gain of $2/MWh during this period. In contrast, when the settlement period and transaction period are mismatched, the participant incurs a $3/MWh loss. Its loss results from a price change during a period when the participant was *not even participating* in the market.

Mismatching settlement periods and transaction delivery periods is inefficient. The inefficiency occurs because if market participants face price risk for periods when they are not participating in the market, they will raise their Interface Bids to compensate for the additional risk. Higher participant Interface Bids to move power from the low-cost to the high-cost region will impede price convergence between the two regions, impeding the ability of the Coordinated Transaction Scheduling system to lower the two region's total production costs.

D. EXTERNAL INTERFACE CONGESTION

Q: What is congestion?

A: Congestion is a condition in which transmission system operating limits prevent unconstrained economic dispatch of the power system. Congestion is captured in the Congestion Component of the LMP. The Congestion Component of the LMP will differ across locations within the New England transmission system whenever one (or more) internal transmission limits are binding.

Q: Does the ISO calculate a Congestion Component of the real-time LMP associated with an external interface limit?

A. No. Under the current inter-regional trading system, the ISO's external transaction scheduling process does not generate the information necessary to establish an economically-correct congestion price associated with a binding external interface limit.

Q: Please explain.

A: From an economic perspective, the cost of congestion between two regions should reflect the "value" of additional transmission capability between the two regions. In this context, the term "value" has a precise meaning: It means the incremental reduction in the two systems' combined total production costs that would be realized if a binding transmission constraint that limits interchange between the two regions was alleviated with an additional unit of transmission capability.

As discussed previously, under the current inter-regional scheduling system the ISOs do not exchange information about the marginal cost of power on their respective sides of the interface during the scheduling process. That means it is not possible for the ISO to evaluate the incremental reduction in the two systems' total production costs that would be realized with an additional unit of transmission capability between the two regions. Put in simple terms, the ISO does not calculate the real-time congestion price associated with a binding external interface today because the ISO does not possess the information this requires.

Q: What does the ISO do today? That is, what value does it assign to the Congestion Component of the real-time LMP associated with an external interface limit?

A. Under the existing system, the ISO sets the congestion component of the real-time LMP associated with a binding external interface limit to zero.

Q: Is the ISO proposing to change this practice when it implements Coordinated Transaction Scheduling?

A. Yes. A benefit of the coordinated economic clearing process to be used for real-time external transactions under Coordinated Transaction Scheduling is that it will enable the ISO to set a congestion component for the external interface LMP when there is a binding external interface limit.

Q: Please explain.

A: As noted previously, the coordinated economic process of clearing an Interface Bid involves comparing the participant's Interface Bid price to the expected difference in LMPs across the external interface that would occur of the transaction is accepted. This involves an exchange, or pooling, of each ISO's information about the impact of the Interface Bid on the incremental cost of sending (and receiving) another megawatt of power across the interface. When the external interface is binding at the time it is scheduled, the difference between one ISO's incremental cost of sending power and the other ISO's decremental cost of receiving power comprises the total congestion price across the interface.

The ISO, and the NYISO, propose to incorporate this difference, less the net amount paid to the marginal (*i.e.*, last accepted) Interface Bid, into the congestion components of their real-time LMPs associated with an external interface under Coordinated Transaction Scheduling.

Q: To be clear, the reason the ISO cannot do this today is because it does not coordinate economic clearing of real-time external transaction with the adjacent ISO?

A. Yes.

Q: Since the external interface is common to both ISOs, is there a double-counting problem if each ISO incorporates an external interface congestion component into its real-time LMP when the external interface limit binds?

A. Because the congestion price equals the difference between the incremental and decremental costs of the exporting and the importing ISO, respectively, it does not work to have each ISO charge the total congestion price to its internal participants. That would result in the double-counting of congestion charges. Instead, the combined congestion components must equal the desired total congestion price across the external interface.

To avoid this double-counting, the ISO and NYISO have each recognized explicitly in their respective tariff provisions addressing Coordinated Transaction Scheduling that congestion costs must take account of the effect of a binding constraint that limits the external interface's schedule. The total of the two regions' congestion components of the real-time LMPs associated with an external interface will add up to the desired total congestion price determined at the time the interface is scheduled, *viz.*, the difference between one ISO's incremental cost of sending power and the other ISO's decremental cost of receiving power, less the net amount paid to the marginal (*i.e.*, last accepted) Interface Bid. NYISO addresses this in its filing materials on page 13 of the NYISO CTS Transmittal Letter.[2] ISO-NE addresses this in the proposed tariff revisions in Section III.2.6(a), which states in relevant part that the Real-Time LMP associated with an external interface will be adjusted for the effect on New England congestion costs of a binding constraint limiting the external interface schedule.

Q: Is the ISO proposing changes to congestion pricing in the Day-Ahead Energy Market?

A: Yes. The ISO will enable congestion pricing in the Day-Ahead Energy Market at external interfaces that are subject to Coordinated Transaction Scheduling in real-time.

Q Please explain.

[2] *See* New York Independent System Operator, Inc., *Proposed Tariff Amendments to Add External Coordinated Transaction Scheduling Market Rules and Request for Waiver*, Docket No. ER12-701-000 (filed December 28, 2011) ("NYISO Transmittal Letter").

A: Presently, the ISO administratively sets the congestion component of the day-ahead LMP associated with a binding external interface limit to zero.[3] That means even if an external interface limit is binding when the Day-Ahead Energy Market clears, the congestion component of the day-ahead LMP associated with the binding external interface is zero.

The reason for this practice is to enforce consistency between the market models used to calculate prices in the Day-Ahead and Real-Time Energy Markets. As discussed previously, under the current inter-regional interchange system, the ISO does not have the information necessary to calculate a congestion component of the real-time LMP associated with a binding external interface limit, so by default sets that component to zero. Consistent with that practice, the ISO sets the analogous congestion component to zero in the Day-Ahead Energy Market.

Q: What exactly will be changed in the Day-Ahead Energy Market?

A: We are removing administrative pricing of the congestion component of the day-ahead LMP associated with an external interface limit, at external interfaces subject to Coordinated Transaction Scheduling in real-time. This is desirable because the analogous congestion component of the real-time LMP will no longer

[3] Section III.2.6(a) of Market Rule 1 states in relevant part: "The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node."

be zero under Coordinated Transaction Scheduling, as described previously. Accordingly, there is no need for the ISO to administratively set the value of the corresponding congestion component of the day-ahead LMP to zero. Instead, it will be set by the bids and offers cleared in the Day-Ahead Market when the external interface limit binds.

Q: What is the practical implication of this change?

A: As a result of this change, the Day-Ahead market's congestion component will reflect the expected corresponding Real-Time congestion component. This is the economic rationale for removing the aforementioned administrative pricing provision. In effect, this change allows the Day-Ahead LMP to incorporate that market's expected frequency, and cost, of real-time congestion across the external interface. This is desirable, as it may help participants to manage the costs of congestion through their day-ahead transactions.

Q: Is the ISO proposing changes to Financial Transmission Right ("FTR") markets?

A: No. The ISO is not proposing to change any of the rules regarding Financial Transmission Rights under Coordinated Transaction Scheduling. The ISO presently offers FTRs that source or sink at its external interfaces in its regular FTR auctions.

Note, the value of an FTR with a source or sink at an external interface subject to Coordinated Transaction Scheduling may change in the future, since the Day-Ahead Energy Market will be able to price congestion at the external interface.

Q: Is the ISO proposing any other changes to pricing or clearing in the Day-Ahead Energy Market to implement Coordinated Transaction Scheduling?

A: No.

E. ELIMINATION OF FEES, CHARGES, AND CREDITS ON EXTERNAL TRANSACTIONS

Q: Please describe the specific types of fees, charges, and associated credits that the ISO proposes to no longer apply to external transactions under Coordinated Transaction Scheduling?

As explained above, the ISO's proposed changes to its fees, charges, and credits under Coordinated Transaction Scheduling are narrowly focused on exempting affected external transactions in an effort to eliminate cross-border transaction costs that inefficiently distort trade between regions and raise the total costs of operating the power system. The ISO is proposing to eliminate the following fees, charges and credits. Note that because wheeling transactions are specifically excluded from the definition of Coordinated External Transactions, the following fees, charges and credits are not eliminated for transactions to wheel energy into, out of or through New England.

- Day-ahead and real-time NCPC charges and credits, including (1) so-called "economic" NCPC charges for fees to support the posturing of resources, costs associated with cancelled starts, resources not dispatched in real time, and synchronous condensers, (2) "make whole" payments to resources that are committed and dispatched, (3) charges associated with a shortage of congestion revenue, and (4) other ancillary NCPC charges and credits.
- Credits and charges associated with the purchase of energy from and the sale of energy to neighboring control areas in the event of an emergency. [Section III.3.2.6]
- Credits associated with the purchase of Security Energy, which is energy that is purchased from the New Brunswick System Operator to preserve minimum flows for transmission system reliability. These credits are eliminated through excluding contributions from Coordinated External Transactions from the Real-Time Load Obligation for purposes of determining the Marginal Loss Revenue Load Obligation [Section III.3.2.1(b)(v)].
- Credits and charges for Inadvertent Energy, which is the difference between the actual energy that flows and the scheduled energy that flows into or out of the New England Control Area [Section III.3.2.1(l)].
- Charges associated with the costs of Regulation service provided to New England. [Section III.3.2.2]

F. CONFORMING CAPACITY MARKET REVISIONS

Q: Why is the ISO proposing revisions to the Forward Capacity Market rules as part of the Coordinated Transaction Scheduling project?

A: There are two reasons. The first is to align the scheduling obligations of New England Import Capacity Resources with the proposed Coordinated Transaction Scheduling design. This serves to promote efficient net interchange scheduling. The second reason is to simplify certain capacity import procedures for market participants with Import Capacity Resource obligations into New England that are associated with supply resources physically located in New York.

Q: Are the proposed revisions to the Forward Capacity Market rules limited in scope to obligations of Import Capacity Resources?

A: Yes. In fact, they are limited in scope to the obligations of those Import Capacity Resources that (1) are associated with supply resources physically located in New York, and that (2) qualify in the Forward Capacity Market as an Import Capacity Resource across an external interface for which Coordinated Transaction Scheduling is implemented.

Q: Please summarize the proposed revisions to the Forward Capacity Market.

A: The primary changes are two, corresponding to the reasons above. First, a New England Import Capacity Resource associated with a supply resource (*e.g.,* a generator) physically located in New York will be obligated to offer the resource and participate in the NYISO day-ahead and real-time energy markets, consistent with the obligations of a New York ICAP resource. [Section III.13.6.1.2.3.] In combination with the coordinated economic clearing process under Coordinated Transaction Scheduling, this requirement will help ensure the resource's output increases the net interchange schedule toward New England whenever the increase improves efficiency and lowers total production costs.

Second, the Import Capacity Resource will no longer be obligated to offer a real-time import external transaction into the New England real-time energy market. The Import Capacity Resource may choose to submit a real-time external transaction, in the form of an Interface Bid, but is not obligated to do so. This will simplify procedures for market participants with New England Import Capacity Resource obligations associated with supply resources physically located in New York.

Q: Let's address each of these changes in turn. First, why is the ISO proposing to require New England Import Capacity Resources associated with supply resources located in New York to participate in the NYISO day-ahead and real-time energy markets?

A: The main reason is to ensure that the physical resource located in New York is available (committed by the NYISO) whenever it is expected to be economic the next operating day, and dispatched up during the operating day whenever doing so contributes to an economic interchange schedule into New England enabled by Coordinated Transaction Scheduling.

An example may help. Suppose that in the course of its normal internal dispatch, NYISO dispatches the New England Import Capacity Resource to a higher output level and, as a result, displaces production from a higher-cost generator in New York. This will tend to reduce New York's LMP. If New York's LMP is less than New England's LMP at the time, the reduction will widen the price spread across the external interface. Under the coordinated economic clearing process of Coordinated Transaction Scheduling, this wider price spread between regions will lead a greater quantity (in megawatts) of Interface Bids to be cleared, increasing the net interchange schedule toward New England.

In this way, the energy produced within New York by a generator with a New England Import Capacity Resource obligation will effectively help serve load in New England when the LMP is higher in New England than in New York. This is consistent with the overall goal of Coordinated Transaction Scheduling to improve net interchange scheduling, and with the efficient use of an Import Capacity Resource. Note that to achieve this objective, the generator within New York with the Import Capacity Resource obligation must be dispatched by the NYISO based upon a competitive generation offer. To ensure the latter, the ISO is requiring New England Import Capacity Resources physically located in New York (that qualified at an external interface subject to Coordinated Transaction Scheduling) to participate in the NYISO's energy markets, consistent with the obligations of a New York ICAP resource.

In a similar way, if we changed the foregoing example to reverse the assumed relative prices so that New York's LMP is greater than New England's LMP, then the initial net interchange schedule should be into New York. In this case, additional energy produced by an economically dispatched generator within New York will tend to shrink the price spread across the external interface, and shift the *net* interchange schedule incrementally toward New England. Again, this is consistent with the overall goal of Coordinated Transaction Scheduling to improve net interchange scheduling, and with the efficient use of an Import Capacity Resource. And again, to fulfill this objective, the Import Capacity Resource's generation facility in New York must be on-line and following economic dispatch by the NYISO.

Q: Let's turn now to the real-time external transaction offer component of the proposed Import Capacity Resource changes. Today, is an Import Capacity Resource obligated to submit a real-time external transaction import offer into New England?

A. Yes. Under the current system, a market participant with a New England Import Capacity Resource obligation is required to submit a real-time external transaction import offer into New England. In addition, the import offer price is subject to an offer price cap. Together, these requirements are termed a "competitive offer" requirement for Import Capacity Resources. [Section III.13.6.1.2.1]

Q: With implementation of Coordinated Transaction Scheduling, will a participant with an Import Capacity Resource obligation be required to submit a real-time Interface Bid into New England?

A: No. The Import Capacity Resource will no longer be obligated to offer a real-time import external transaction into the New England real-time energy market. The Import Capacity Resource may choose to submit a real-time external transaction, in the form of an Interface Bid, but is not obligated to do so.

Q: Why not?

The market incentives and coordinated scheduling process under Coordinated Transaction Scheduling make such a requirement unnecessary. There are several reasons for this.

First, requiring an Import Capacity Resource to submit a real-time Interface Bid is unnecessary under the Coordinated Transaction Scheduling design that requires the associated generation facility in New York to participate competitively (*i.e.*, consistent with its competitive reference level) in the NYISO energy markets. The NYISO will evaluate the generation facility for commitment in the energy market, and it will be committed when economic. Once online, the facility's generation supply offer will be incorporated in NYISO's market offer data used by the coordinated economic clearing process to determine the net interface schedule.

As described by example previously, this system provides that the energy from the generation facility associated with a New England Import Capacity Resource will increase the net interchange schedule toward New England when doing so improves efficiency. This is true regardless of which market participants submitted Interface Bids. Moreover, it is also true if the market participant with the Import Capacity Resource obligation did not submit an Interface Bid, provided that other market participants submitted Interface Bids.

That observation brings us to the second point. The economic design of the Coordinated Transaction System is structured so that market participants will, in the aggregate, submit many Interface Bids each scheduling interval. There are two reasons for this. First, Interface Bids may be submitted by any market participant, and they are costless to submit. This is because both ISOs are eliminating their cross-border transaction costs, as described previously. Second, the coordinated economic clearing process for each Interface Bid ensures that a bid will be cleared only if the bidder's expected net profit exceeds the bid price. In plain terms, a participant that clears an Interface Bid with a positive bid price is expecting to "buy low" in one region and "sell high" in the other. By design, in doing so, the cleared Interface Bid increases the net interchange schedule from the low-to-high price region. This alignment of market participants' private economic interests with the broader societal interest in minimizing the two regions' combined production costs creates a well-designed market incentive for participants to submit, in the aggregate, a large quantity of Interface Bids between regions—

rendering it unnecessary for a participant with an Import Capacity Resource to be required to submit an Interface Bid.

Last, it is useful to note that requiring an Import Capacity Resource to submit an Interface Bid into New England would have no effect at all unless it also capped the submitted Interface Bid price at or *below* the market-clearing (that is, marginal) price of all accepted Interface Bids. This is because any Interface Bid submitted above the market-clearing price will not clear, and therefore not affect the quantity of power scheduled across the external interface[c1]. Given the anticipated competitive nature of Interface Bids, placing an obligation upon a market participant to submit an Interface Bid capped at a bid price that is *below* the market-clearing price of all accepted Interface Bids may produce an undesirable market distortion in and of itself.

Q: Will New England Import Capacity Resources physically located in New York remain subject to deliverability and availability obligations?

A: Yes.

Q: How is the applicability of Import Capacity Resource penalties affected by the implementation of Coordinated Transaction Scheduling?

As part of implementing Coordinated Transaction Scheduling, the ISO is making conforming changes to the provisions for several existing penalties. The purposes of such penalties, and the associated penalty rates, are unchanged.

In brief, the rationale for the conforming changes to the existing penalty provisions are:

- **Failure to Offer.** Today, a failure to offer occurs, under the provisions contained in Section III.13.7.2.7.2.1(a) and (b), if a New England Import Capacity Resource fails to submit a real-time and day-ahead external transaction import offer, or if such import offer does not meet the offer requirements, including the quantity (megawatt) and compliance with the offer price cap as required by the "competitive offer" requirement.

  As discussed previously, the ISO proposes not to require New England Import Capacity Resources physically located in New York (that qualified at an external interface at which Coordinated Transaction Scheduling is implemented) to submit a real-time external transaction import offer. Accordingly, the failure to offer penalty will no longer apply in the event such a resource does not submit a real-time external transaction (Interface Bid) import offer.

  Note, however, that the ISO is retaining the existing offer requirement and associated failure-to-offer penalty provisions for Day-Ahead external transaction import offers from New England Import Capacity Resources, at all external interfaces.

- **Failure to deliver.** Today, under the provisions contained in Section III.13.7.2.7.2.1(c), the failure to deliver penalty occurs when energy associated with a capacity resource is not delivered into New England across an external interface when the ISO requests (i.e., clears) the associated real-time external transaction import. Today this can occur for several different reasons, including a "check out" failure of the associated real-time external transaction (today submitted separately to each ISO); the Import Capacity Resource supply resource in the source region being offline during a period when the source region is experiencing an operating reserve deficiency; and other conditions. Certain exceptions exist to the applicability of the failure to deliver penalty; for example, no penalty is applied if the failure to deliver occurs because the transmission limit of the relevant external interface is binding.

For New England Import Capacity Resources physically located in New York that qualified at external interfaces subject to Coordinated Transaction Scheduling, "check out" failures will no longer be relevant. A failure-to-deliver penalty will be assessed if several conditions hold. Specifically, if (a) upon the ISO's request, the NYISO indicates that the total quantity of energy that may be delivered to New England is limited (to an amount less than the request), and (b) this limit constrains the net interchange determined during coordinated economic clearing, and (c) the limit occurs because one (or more)

Import Capacity Resources are not available or deliverable to New England, then the Import Capacity Resources that are not deliverable are subject to the existing failure-to-deliver penalty provisions. Otherwise, Import Capacity Resources qualified at external interfaces subject to Coordinated Transaction Scheduling will not be assessed failure-to-deliver penalties. Certain existing exemptions to this penalty, such as non-deliverability due to a binding transmission limits across the relevant external interface, will remain in place. [Sections III.13.7.2.7.2.1. and III.13.7.2.7.2.2(a)]

- **Shortage Event Penalty.** The existing shortage event penalty will continue to apply to New England Import Capacity Resources. Eligibility for this penalty is ascertained, in the event of an FCM Shortage Event, similarly to the process for ascertaining eligibility of a failure to deliver penalty for Import Capacity Resources at an external interface for which the ISO has implemented Coordinated Transaction Scheduling. Today, the ISO reviews the delivery performance of the Import Capacity Resource's real-time external transaction import offer. Under Coordinated Transaction Scheduling, the ISO will review information regarding the actual operation of the Import Capacity Resource's associated supply resource (*e.g.,* a generator) physically located in New York during the Shortage Event. [Section III.13.7.1.2.A.]

Q: Are there additional benefits from these revisions to Import Capacity Resource obligations with implementation of Coordinated Transaction Scheduling?

A. Yes. As noted previously, under the current system a New England Import Capacity Resource is required to submit a real-time external transaction import offer into New England at or below a "competitive" offer price cap. This offer price cap is not directly tied to the fuel type, or the marginal cost, of the supply resource located in New York associated with the New England Import Capacity Resource.

For the reasons described previously, with implementation of Coordinated Transaction Scheduling the ISO proposes to replace this requirement with the obligation to offer and participate in the NYISO energy markets, consistent with the obligations of a NY ICAP resource. This means that the supply resource associated with the New England Import Capacity Resource will be evaluated for commitment and for dispatch by the NYISO, based on the resource's competitive supply offer, or competitive reference level, in that market. This accommodates the economic costs of the actual supply resource better than the current "competitive offer" requirement for New England Import Capacity Resources, which is based on a benchmark rather than actual generating unit costs.

V. IMPLEMENTATION OF COORDINATED TRANSACTION SCHEDULING.

Q: Will Coordinated Transaction Scheduling be implemented at all external nodes between New England and its neighboring Control Areas?

A: No. At this time the ISO is working with the New York Independent System Operator to implement Coordinated Transaction Scheduling at the New York Northern AC external interface and the Northport-Norwalk external interface. The tariff revisions in Section III.1.10.7.A of Market Rule 1 reflect this intended implementation. Nevertheless, as the NYISO indicates in its filing materials for Coordinated Transaction Scheduling, at this time only the New York Northern AC external interface has been evaluated for Coordinated Transaction Scheduling implementation.[4] In the event further evaluation reveals that implementation for the Northport-Norwalk external interface is not feasible, the ISO will file a tariff amendment to remove reference to this latter interface before Coordinated Transaction Scheduling becomes effective.

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[4] *See* NYISO Transmittal Letter at fn 25.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 24 February 2012 ____________________
Matthew White

Executed on 2/24/12 ____________________
Janine Dombrowski

Benefits of Coordinating the Interchange Between New York and New England

Presented to:

Joint NYISO/ISO-NE Stakeholder
Technical Conference on Broader Regional Markets

David B. Patton, Ph.D.
Potomac Economics

January 21, 2011

Introduction

- This presentation summarizes our assessment of the benefits of initiatives to improve the efficiency of the interchange between New York and New England.
- Improved scheduling would more fully utilize the transmission interfaces between the markets and generate significant benefits.
  - ✓ The true efficiency benefits are best measured as reduced production costs.
  - ✓ Production costs are reduced as lower-cost resources in one market displace higher-cost resources in the adjacent market.
  - ✓ The result of this process is improved price convergence between the markets.
  - ✓ In most cases, the short-term consumer savings (resulting from the price-effects of improved scheduling) would be substantially higher than the production cost savings.
- Our previous assessments have consistently found that coordination would lead to significant reductions in production costs and consumer costs.
- This assessment expands the analysis to estimate the benefits of specific proposals for coordinating the interchange between New York and New England.

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Updates to the Analysis of Improved Interchange

- Our previous simulations estimated the benefits that would result from optimal scheduling of the interfaces between the markets.
  - ✓ However, the portion of the benefits that are ultimately realized depends on the effectiveness of the market solutions that are implemented by the ISOs.
- The ISOs are currently evaluating the benefits of specific proposals that will improve, but will not perfectly optimize the interchange due to uncertainties.
- The results that are discussed in this presentation compare the benefits from optimal scheduling to the benefits that would result from two specific proposals:
  - ✓ <u>Tie Optimization</u> – The ISOs exchange information 15 minutes in advance and optimize the interchange based on a prediction of market conditions. The interchange would be adjusted every 15 minutes.
  - ✓ <u>Interface Bidding</u> – Identical to Tie Optimization, except the interchange schedule is only adjusted to the extent that market participants have submitted intra-hour interface bids priced below the predicted price difference between markets.

Modeling Specific Interchange Proposals

- To quantify the share of potential benefits that would be captured by each proposal, we performed the simulations using three sets of assumptions:
  - ✓ Ideal Interchange – Assumes the interchange is adjusted to the optimal level based on perfect information. The adjustment in interchange increased toward the higher-priced market until: (i) the interface is fully loaded, (ii) internal constraints prevent additional re-dispatch, or (iii) the adjustment reaches 500 MW.
  - ✓ Tie Optimization – Assumes the interchange is adjusted to the forecasted optimal level. The ISOs' forecast may differ from actual conditions, so the resulting interchange may not be optimal.
    - For NYISO, we use the advisory price produced by the RTD that precedes the quarter hour RTD case.
    - For ISO-NE, we use its hour-ahead forecast. The forecast errors are larger than the errors in New York understandably. We reduce the errors by 50 percent to account for the expected increase in accuracy when the timeframe is shortened.
  - ✓ Interface Bidding – Same as Tie Optimization, except an assumed interface "bid stack" limits re-dispatch when the marginal bid the forecasted price difference.
- Comparing the results of these simulations allows us to evaluate the efficiency of specific proposals compared to ideal interchange scheduling.

Discussion of Assumptions Used in Simulations

- Use of Interval Data – In past analyses (e.g., in Annual Reports), we estimated the optimal interchange using historic hourly-integrated real-time data, while these simulations use real-time data at the interval level.
  - ✓ The use of hourly data resulted in conservative estimates by assumed one interchange value for the hour -- it is usually efficient to adjust the interchange throughout the hour.
  - ✓ This analysis allows adjustments each 15 minutes.
- 500 MW Limit on Adjustments – The latest simulations impose a 500 MW limit on the size of the adjustment in the interchange in any interval (past simulations had no limit).
  - ✓ The simulation model does not “see” internal transmission constraints that would bind due to the interchange adjustment, so this limit reduces tendency to over-estimate potential re-dispatch.
- Consumer Savings – These are calculated as the change in real-time prices times the load affected by the price change.
  - ✓ The load affected is limited by congestion (e.g., binding constraints into SE New York limit the downstate consumer savings).
- Negative-LBMP Intervals – We exclude intervals when the New York border price is negative, since these are likely to become far less prevalent after (i) the HQ interface is scheduled on a 5-minute basis and (ii) the regulation demand curve is modified.

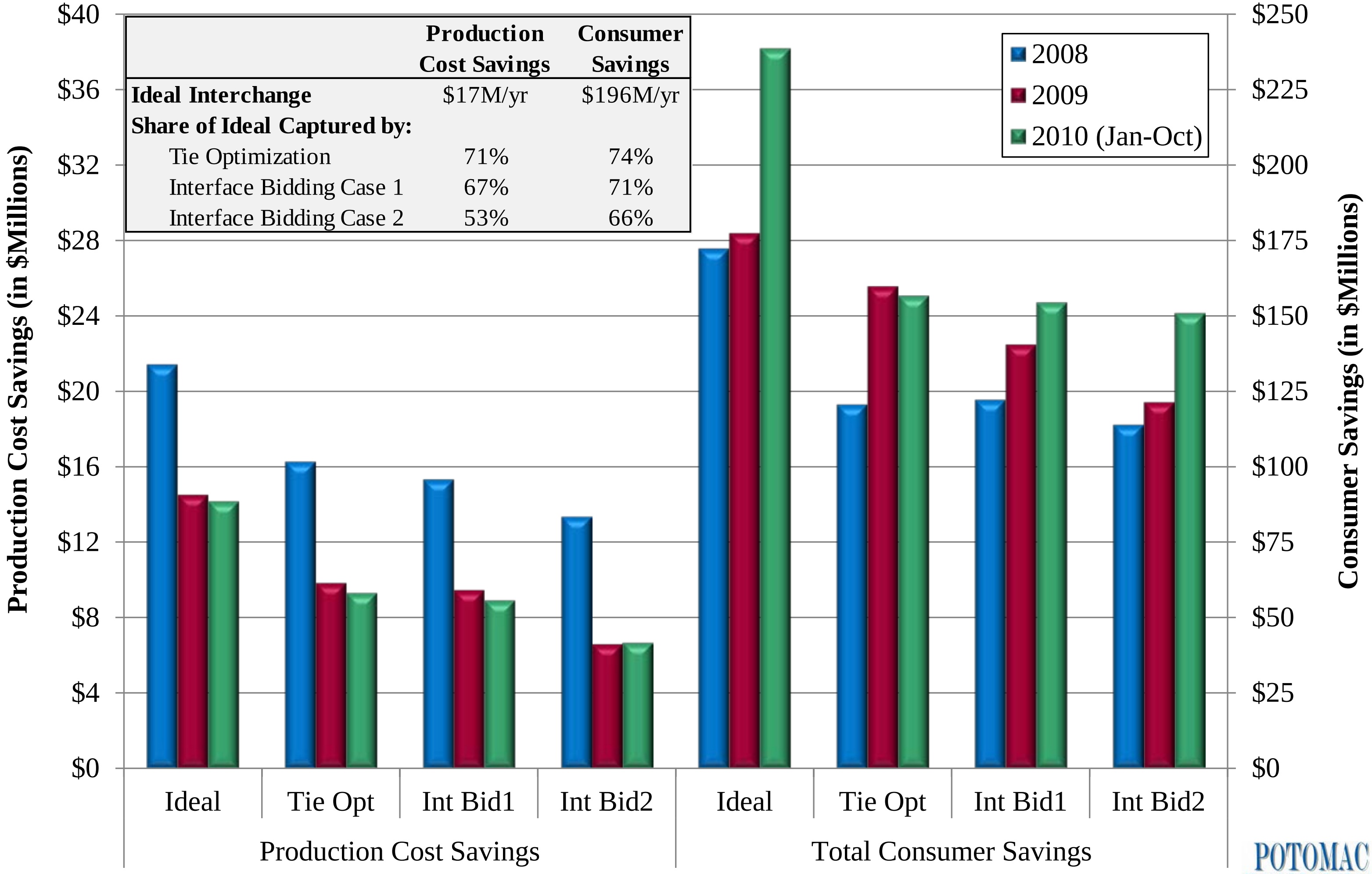
Discussion of Assumptions Used in Simulations

- Top of the Hour: Our simulations exclude intervals at the top of each hour.
  - ✓ These intervals are frequently affected by ramp constraints and other conditions that lead to transient price spikes that our simulations are not designed to model accurately.
  - ✓ Hence, we conservatively estimate zero benefits from these intervals, although it is likely that the interchange would be improved in these intervals.
- Congestion Assumptions: The simplified network model used in our simulations is based on active constraints, and assumes no re-dispatch after the interchange adjustments.
  - ✓ This is conservative because redispatch may occur that would produce additional savings that we do not capture.
  - ✓ For example, the scope of the consumer savings could be broader than we estimate if optimal redispatch would reduce or eliminate congestion on active constraints.
- Interface Bidding assumption: We assumed a interface bid stack beginning at zero and rising linearly up to $10 at 500 MW in the first case, and rising linearly to $40 at 500 MW in the second case.

Production Cost Savings and Consumer Savings

- The following figures show the estimated production cost savings and consumer savings for each of the cases that we analyzed.
- The average production cost savings was roughly $18 million per year, although this is likely conservative as a long-run expectation because:
  - ✓ One quarter of the hour is not included;
  - ✓ The supply and demand conditions in both areas were not as tight as they are likely to be in the long run and shortages were relatively infrequent; and
  - ✓ Fuel prices were relatively lower for much of this period.
- The results show that roughly 70 percent of the efficiency benefits are captured by tie optimization and only slightly less by the lower priced interface bids.
  - ✓ The higher-priced interface bids degrades the benefits to 54 percent of the ideal case.
- The figure also shows that consumer savings in the ideal case average almost $200 million per year, which is conservative for the same reasons as listed above.
  - ✓ Nearly three-quarters of the savings are captured by tie optimization, which falls only slightly to 71 percent with low-priced interface bids.
- The second figure shows that the consumer savings accrue to both areas, although the relative savings has shifted year-to-year as congestion patterns and supply conditions have changed.

Production Cost Savings and Consumer Savings



	Production Cost Savings	Consumer Savings
Ideal Interchange	$17M/yr	$196M/yr
Share of Ideal Captured by:		
Tie Optimization	71%	74%
Interface Bidding Case 1	67%	71%
Interface Bidding Case 2	53%	66%

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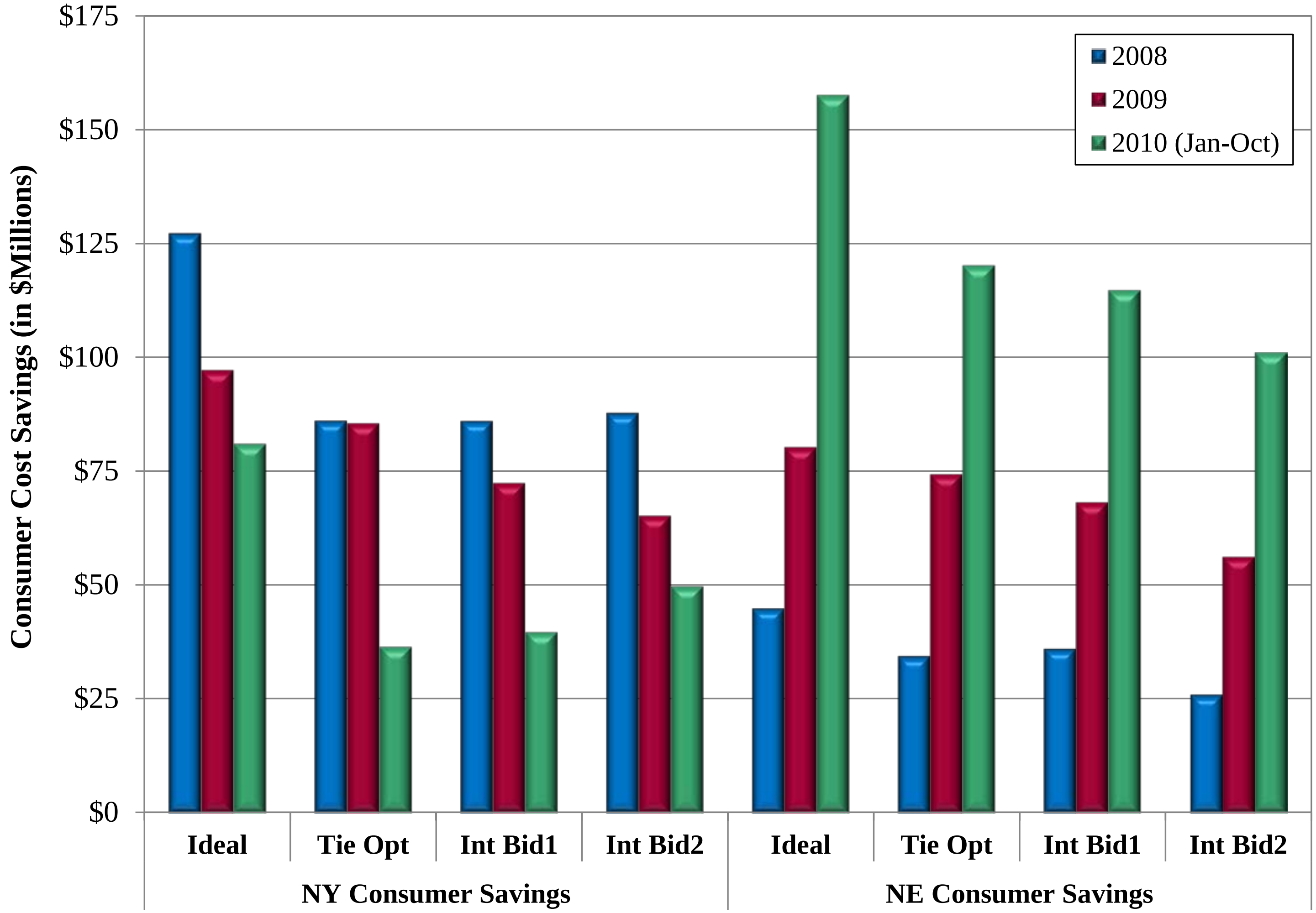
Production Cost Savings and Consumer Savings



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Other Simulation Results

- The following table provides some additional detail regarding the results of the simulation.
- It shows that in each year, the adjustments occur relatively evenly in both directions, which contributes to consumer savings in both areas each year.

	Ideal Interchange				Tie Opt	Int Bid 1	Int Bid 2
	2008	2009	2010	2008-10	2008-10	2008-10	2008-10
Flow Adjusted Into NY (% of intervals)	42%	46%	44%	44%	43%	43%	43%
Flow Adjusted Into NE (% of intervals)	41%	44%	45%	43%	42%	42%	42%
When Flow Adjusted Into NY:							
Avg. Adjustment (MW)	266	259	265	264	262	186	101
Avg. System LBMP Change in NY ($/MWh)	-$10.63	-$7.19	-$7.07	-$8.30	-$8.24	-$7.11	-$5.64
Avg. System LMP Change in NE ($/MWh)	$7.00	$2.96	$3.39	$4.45	$4.84	$3.95	$2.75
When Flow Adjusted Into NE:							
Avg. Adjusted Interchange (MW)	-226	-220	-237	-228	-210	-153	-89
Avg. System LBMP Change in NY ($/MWh)	$7.96	$4.36	$4.83	$5.72	$6.73	$5.62	$4.14
Avg. System LMP Change in NE ($/MWh)	-$8.21	-$4.93	-$7.43	-$6.86	-$6.88	-$5.87	-$4.39

Conclusions and Recommendations

- These results show sizable efficiency and consumer savings in all cases analyzed, which supports the ISOs' initiative to pursue improved interface scheduling.
  - ✓ For the reasons we have discussed, these savings are likely to be conservative and would be larger under tighter supply/demand conditions over the long-run.
  - ✓ These savings are larger than the potential savings available from most other initiatives and should, therefore, be a relatively high priority.
- While tie optimization is superior to interface bidding, the benefits are very similar if participants submit relatively low-cost interface bids.
- Questions?

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Potential Trigger to Switch from CTS to TO

Presented by:

David B. Patton
President

August 9, 2011

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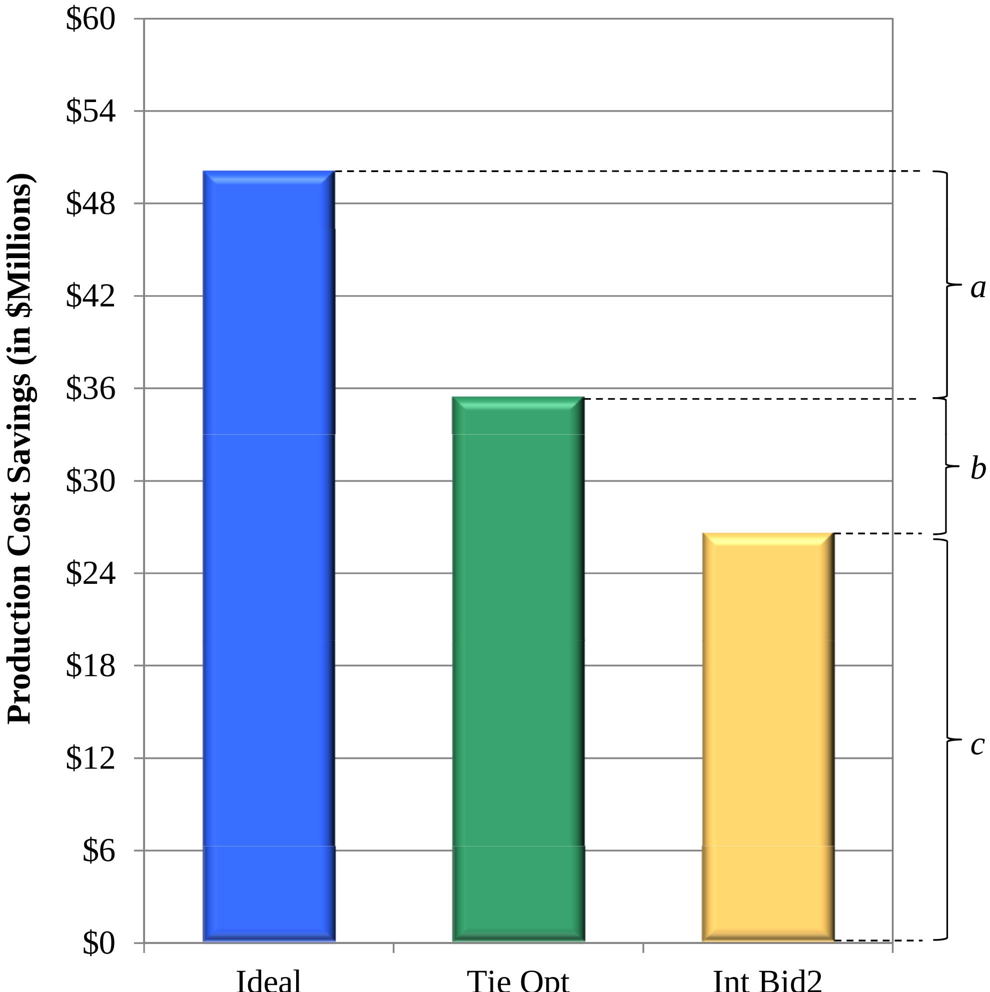
Summary of Proposed Trigger

- NYISO and ISO-NE have discussed with us the possibility of developing a "trigger" that would compel the RTOs to move to Tie Optimization if CTS is implemented.
- This presentation describes a trigger that has been considered and specifies parameters that would allow the trigger to be reasonable.
- The MMU to perform an evaluation to quantify the forgone savings that could have been achieved under the Tie Optimization option.
- In order to be reasonable, a trigger should: 1) Be based on values that can be objectively quantified; and 2) Identify poor performance that is attributable to CTS and not other factors.
- The figure below illustrates a proposed trigger that would satisfy these principles.
  - ✓ The figure shows the estimated benefits of TO and CTS, in comparison to the ideal interchange case.
  - ✓ The CTS case (labeled "Int Bid2") is a scenario where the we assumed relatively high-priced interface bids, resulting in lower savings and poorer performance than the more realistic CTS scenario ("Int Bid1").

Illustration of Proposed Trigger: Based on Results of the Benefits Study



Results for 1/2008 - 8/2010		
a	=	$15M
b	=	$9M
Ratio $\frac{b}{a}$	=	60%

Proposed Trigger		
Ratio $\frac{b}{a}$	>	60%
and		
b	>	$3 Million/Year

Notes:

a and *b* can be quantified for the post-CTS period being evaluated.

c cannot be quantified because the "but-for" world without CTS will not exist.

Therefore, only *a* and *b* should be included in the trigger formula.

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Summary of Proposed Trigger: Ratio Component

- The first component of the proposed trigger is based a ratio of:
  - ✓ *b* = the difference in savings between the TO Case and the CTS Case;

    divided by:
  - ✓ *a* = the difference in savings between the Ideal Case and the TO Case.
- This ratio is a reasonable basis for the trigger because *a* represents the loss in savings due to forecast errors by the ISOs.
  - ✓ Participants' bids should be positively correlated with *a* because larger forecast errors will lead to higher risk for the participants.
  - ✓ The ratio, therefore, allows for a larger gap between the savings of CTS and TO when forecast errors are larger because the ISOs should work to improve the forecasts rather than failing over to TO in this case.
  - ✓ This estimated ratio from the benefits study for the Int Bid2 case is 60% -- we propose a trigger ratio of 60%.

Summary of Proposed Trigger: Production Cost Component

- The second component of the proposed trigger is a $3 million floor on the difference in production cost savings between TO and CTS.
  - ✓ This floor establishes a lower bound on the lost savings that would be required to justify a filing to switch from CTS to TO.
- This is necessary if the ISO’s forecasts are very accurate, which could:
  - ✓ Result in a very small *a* that would make the ratio trigger alone unreasonable (because a very small *b* could still result in a ratio > 70%).
- The $3 million threshold level had been proposed previously and is slightly larger than the differential in the Int Bid 2 scenario.
  - ✓ Int Bid2 simulates a poorly performing CTS during a period when savings would have been low due to the low fuel prices and high capacity surpluses.
  - ✓ Iit is a reasonable floor to use in the trigger because under conditions likely to lead to higher savings, the ratio should govern the filing to switch to TO.
- Finally, stakeholders should consider the timeframe over which the trigger applies.
  - ✓ We believe it should have to be satisfied for in year 1 *and* in year 2 along because performance of new market rules often improve substantially as participants gain experience with them.

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ISO White Paper

Inter-Regional Interchange Scheduling (IRIS)

Analysis and Options

January 5, 2011

ISO New England and New York ISO

Inter-Regional Interchange Scheduling: Analysis and Options

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ISO White Papers are intended to facilitate discussion of technical market, planning, and operational issues among stakeholders and ISO staff. This white paper reflects analysis and options developed jointly by the New York ISO and ISO New England. In the event a representation herein differs from provisions of an ISO's tariff, the tariff shall prevail.

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EXECUTIVE SUMMARY

In July 2010, ISO New England Inc. (ISO-NE) and the New York Independent System Operator (NYISO) commenced a joint project to evaluate the economic and operational performance of energy interchange on their interconnected transmission network. This long-term project has two phases. Phase I, from 2010-2013, seeks to improve economic coordination between the two regions' electricity markets. Phase II, from 2012-2014, will focus on coordinated congestion management and network modeling.

This White Paper is the initial Phase I report. It evaluates the performance of the current inter-regional interchange system, describes alternative market procedures that could improve this performance, and provides preliminary economic benefit estimates from these improvements. The purpose of this White Paper is to facilitate stakeholder discussion of these options, and develop consensus recommendations that NYISO and ISO-NE can refine and implement.

THE STATUS QUO

To enable physical trade of power requires an extensive set of market rules and procedures. The market monitor for NYISO and the (external) market monitor for ISO-NE, Potomac Economics, has expressed concern that the current rules governing inter-regional trade yield frequent price disparities between regions.[1] Unless the transmission network is congested, these price disparities imply low-cost generation is used too little and high-cost generation is used too much. That runs counter to the ISOs' shared objective of meeting demand at the minimum production cost.

The current inter-regional interchange system between New York and New England does not realize all of the potential benefits from trade between regions. Analysis in this report indicates that improved scheduling would produce significant benefits. Ideally, power should flow from the region with lower costs to the region with higher costs. However, the region with lower costs switches back and forth frequently—often reversing within each day. The current scheduling system cannot react quickly to these changes. As a result, at the primary transmission interface between NYISO and ISO-NE power flows in the wrong direction—from the high-priced region to the low-priced region—more than 4000 hours per year.

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[1] Potomac Economics, Ltd., External Market Monitor for ISO New England Inc., *2009 Assessment of the Electricity Markets in New England* ("New England Assessment"); Potomac Economics, Ltd., Market Monitor for the New York ISO, *2009 State of the Markets Report for New York ISO* ("New York Report").

In addition, data indicate that during the remaining hours of the year there is ample transmission capacity available to move additional power from the lower-cost region to the higher-cost region. As a result, production costs would be lower if the existing transmission interconnections were scheduled efficiently.

Potomac Economics estimated the economic benefits that could have been achieved if the transmission interconnections between New York and New England were scheduled efficiently. Comparing the status quo to an efficiently scheduled system, the estimated total production cost of meeting demand in the two regions (combined) would have been lower by a cumulative $77 million from 2006 through 2010. These production cost savings accrue to both regions.

The cost reductions would also produce lower locational marginal prices (LMPs) in each region. Potomac Economics estimates that if the transmission interface had been efficiently scheduled, loads' total energy expenditures in the two regions would have been lower by a cumulative $784 million from 2006 through 2010. Each region's energy expenditures would be significantly lower in every year examined, with magnitudes that vary by year with fuel costs and system conditions.

SOLUTION OPTIONS

To solve the problem of inefficient tie schedules between ISO-NE and NYISO, the two ISOs established a joint design team to develop solution options and recommendations. This White Paper presents conceptual designs for two solutions: (A) Tie Optimization and (B) Coordinated Transaction Scheduling. Either of these two options would have lower production costs than the status quo and result in significant savings for load.

While other options were examined, such as maintaining the current system with increased scheduling frequency, the two solution options in this report provide the greatest potential efficiency improvement. Each option directly targets the root causes of the inefficiencies in the current inter-regional scheduling system. In addition, each solution option adheres to several key design principles:

- MARKET-BASED SOLUTIONS. The solution options both use competitive, market-based offers to determine the real-time schedule of energy interchange between their interconnected transmission networks.
- ALL SETTLEMENTS AT LMP. All scheduled energy flows between regions are priced at the LMP. This facilitates market transparency and correctly prices congestion.
- ISOS HAVE NO FINANCIAL POSITION IN MARKETS. The ISOs do not directly participate in the markets and do not buy or sell power. The ISOs continue to act as independent settlement administrators for the payments to and from market participants.

Both Tie Optimization and CTS employ several common elements:

- Higher frequency schedule changes across external interfaces;
- Elimination of charges/credits on external transactions that deter trade;
- Financial instruments (FTR/TCC) to hedge price risk at external interfaces.

To implement these elements, the two solution options share many operational and settlement details. However, they differ in the information they require of market participants. Conceptually, Coordinated Transaction Scheduling (CTS) is more like the current inter-regional trading system: CTS retains a role for external transaction offers to help determine real-time interface schedules between regions. In contrast, the Tie Optimization option is like the least-cost economic dispatch system used internally for each ISO's energy market: It relies on the bid-based supply offers from generators and demand resources to determine real-time LMPs and transmission flows within and between the two ISOs' networks.

Solution Option A: Tie Optimization

The core concept of Tie Optimization is for the ISOs to optimize their external transmission links in the same way, or as closely as possible, that the ISOs optimize transmission internally. This achieves the lowest possible production cost and efficiently uses the existing transmission infrastructure.

The concept that underlies Tie Optimization is not new. It is the same bid-based, security-constrained least cost dispatch logic that underlies the wholesale energy market administered by each ISO. This competitive market design applies to all internal nodes and internal transmission facilities today. Tie Optimization simply extends this standard market design to cover the pool transmission facilities that interconnect the two ISOs.

Operationally, Tie Optimization coordinates real-time energy dispatch across both ISOs' control areas through the exchange of load and offer data every fifteen minutes. This is made possible because of advances in communications and information technology, which allow the ISOs to implement a (near) joint energy dispatch without merging control rooms. We describe this system, called High Frequency Scheduling (HFS), in detail in Part III.

A subset of each ISOs' market participants actively trade energy across the interface today. For them, important considerations are (1) hedging (congestion) price risk at the interface, and (2) fulfilling existing contractual obligations that involve scheduling between ISO regions. To address (1), the ISOs anticipate developing financial products (TCCs/FTRs) that would provide greater hedging ability at the interface than exists today. To address (2), the ISOs would revise certain ISO-specified scheduling obligations to conform to the Tie Optimization system, simplifying the current scheduling requirements,[2] and work with other market participants to handle existing contractual scheduling obligations under the new system.

Solution Option B: Coordinated Transaction Scheduling

The second solution option is a package of external transaction enhancements called *coordinated transaction scheduling* (CTS). Like Tie Optimization, CTS employs higher frequency scheduling (HFS) and eliminates charges/credits on external transactions that deter trade. In contrast to today's inter-regional scheduling system, CTS features:

- A simplified bid format, called an *interface bid*, for real-time scheduling;
- Coordinated acceptance of interface bids by the ISOs, using an improved clearing rule.

Like the current external transaction system, the ISOs would use two sets of market-based offers under CTS to set real-time external interface schedules: (1) participants' external transaction offers to buy and sell across an interface, cleared against (2) the real-time generation supply stacks in each region. However, the structure of the external transaction bid format, and how it clears, differs between CTS and the existing inter-regional trading system. An *interface bid* is a unified transaction to buy and sell power simultaneously on each side of the interface. This bid structure is designed to resolve one of the root causes of the current system's inefficiencies, ensuring that transactions determining real-time flows result in a net interface schedule that moves power from the lower-cost region to the higher-cost region.

As with Tie Optimization, CTS would enable market participants that actively trade energy across the interface today to (1) hedge (congestion) price risk across the interface, and (2) fulfill existing contractual obligations that involve scheduling between ISO regions. To address (1), the ISOs anticipate developing financial products (TCCs/FTRs) that are compatible with CTS and enable greater hedging ability across the interface than exists today. To address (2), the ISOs would revise certain ISO-specified scheduling obligations to conform to the CTS system and work with market participants to handle existing contractual scheduling obligations under the new system.

Recommendations

The ISOs recommend the Tie Optimization option because it is the more efficient solution. This emphasis on efficiency reflects the ISOs' shared philosophy of using competitive wholesale markets to meet power demand at the minimum production

[2] In particular, the scheduling obligations imposed on a participant with a Capacity Supply Obligation to ISO New England associated with a resource physically located in the New York control area.

cost. The CTS system is presented as an option because it has the potential to provide significant efficiency improvements over the current system.

Tie Optimization and CTS will both enable the real-time net tie schedule to be adjusted frequently (every 15 minutes) in response to changing system conditions. This HFS procedure represents an important solution to a second root cause of inefficient schedules today: The inflexibility of current market rules to change tie schedules more frequently than hourly, in a power system where the location of the lowest-cost resource can change every dispatch interval.

The CTS system is not expected to produce as complete a price convergence between regions as Tie Optimization. The profit margin that market participants require to accept real-time price risk between regions when trading power will result in a price difference between New York and New England. That difference means the CTS system will tend to produce less efficient schedules, and higher production costs, than Tie Optimization.

With HFS and the improved clearing rule, it is possible the CTS system might yield price convergence that is nearly as efficient as Tie Optimization. The efficiency loss with CTS is difficult to quantify prospectively because the CTS bid format is a new product without clear parallel in other electricity markets today. The ISOs are actively engaged, with the assistance of Potomac Economics, in an effort to gauge whether production costs would be materially higher with CTS than with Tie Optimization.

I. Inter-Regional Trade

A. Interconnected Markets

New York ISO and ISO New England ("the ISOs") are private, non-profit, regional transmission organizations that serve New York and the New England states, respectively. Each ISO operates the bulk electric power system in its region, and is responsible for the short-term reliability of the power grid. The ISOs seek to carry out these functions in an efficient, cost effective manner. To meet this objective, each ISO administers competitive wholesale markets for electricity, capacity, and related services.

Although the wholesale electricity markets operated by NYISO and ISO-NE are administered separately, the markets are interdependent. Each hour, power flows from one region to the other based on the buying and selling activities of market participants. Across the primary transmission interface between New York and New England, annual scheduled power flows are close to balanced: In 2009, 44 percent (1.6 TWh) of total interchange flowed toward New England, and 56% (1.9 TWh) flowed toward New York.

The fundamental drivers of this inter-regional trade are the variations in electricity demand in each region from one hour to the next, and generation cost differences between regions. In a modern power grid, the location of the lowest-cost generation facility able to serve demand can—and does—change from moment to moment. Accordingly, both the volume and the direction of trade between New York and New England typically change over the course of each day.

Physical Interconnections

The power transmission networks operated by NYISO and ISO-NE are interconnected at their border. Table I-1 lists the nine major transmission links between New York and New England. In total, these links are capable of transferring approximately 1800 megawatts (MW) of power between New York and New England under normal operating conditions. To put this in perspective, 1800 MW is approximately 12% of New England's average power consumption in 2009, and a similar percentage, 10%, of New York's. Thus, in any particular hour, each region could meet a significant portion of its power consumption with imports from the other.[3]

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[3] These interconnections also serve important reliability purposes, and NYISO and ISO-NE have longstanding arrangements to that effect.

Table I-1. Transmission Interconnections Between New York and New England

Interface	Network Path (From / To)	Type	Rating (kV)	Capacity (MW)
NYN	Alps NY / Berkshire MA	AC	345	Eastbound: 1400 Westbound: 1200
	Pleasant Valley NY / Long Mtn CT	AC	345	
	Rotterdam NY / Bear Swamp MA	AC	230	
	Hoosick NY / Bennington VT	AC	115	
	Whitehall NY / Blissville VT	AC	115	
	Plattsburgh NY / Grand Isle VT	AC	115	
	Smithfield NY / Falls Village CT	AC	69	
NNC	Northport NY / Norwalk CT	AC	138	100
CSC	Shoreham NY / New Haven CT	DC		330

Note: Capacity is nominal total transmission capability under normal operating conditions.

Physical transmission links between different regional grid operators are known as *interties*, or simply *ties* for short. The set of seven alternating current (AC) ties labeled "NYN" are called the New York North Interface.[4] The NYN interface comprises the majority of the transmission capacity between the two regions, and accordingly is the focus of this report. All lines in this interface are known as "pool transmission facilities," and the ISOs are responsible for scheduling all power flows across these transmission links.

The two remaining ties in Table I-1 operate differently than the NYN interface. The Cross Sound Cable (CSC) (NYISO: NPX-CSC) and the Northport-Norwalk (NNC) (NYISO: NPX-1385) link run between Connecticut and New York underneath the Long Island Sound. The former is a direct current line, and the latter is a controllable AC line (via phase angle regulators). These lines are used nearly all hours they are in service to deliver power to Long Island.[5]

Unlike the eight AC transmission links (NYN and NNC), the CSC is not a pool transmission facility but has merchant transmission status under FERC regulations. Parties that seek to trade electricity across it must use a different reservation system than the ISOs' process for pool transmission facilities. This report does not evaluate, nor propose any changes to, the reservation and scheduling system governing merchant transmission facilities.

[4] NYISO refers to the NYN Interface as the NYSIO-ISONE interface. This report uses NYN hereafter for brevity.
[5] See Potomac Economics, *2009 Assessment of the Electricity Markets in New England* at 16.

B. Physical and Financial Obligations

To enable physical trade of power requires an extensive set of market rules and procedures. These rules not only affect the physical flow of power, but also influence the cost of operating the power grid and the prices consumers ultimately pay.

Even for market participants that transact energy on a daily basis, the economic logic of the current trading system between New York and New England can be complex. In this section, we distill these market rules and procedures into their key elements and their economic purpose.

The Main Elements

There are four main elements to the current inter-regional trading system:

1. Requests. Market participants submit requests to buy or sell power at the 'border' separately to each ISO (e.g., a request to buy on the New England side and to sell on the New York side);
2. Acceptance. Each ISO independently clears the requests on its side, based primarily on economic comparisons to other requests and to the ISO's generation supply stack;
3. Delivery. During the delivery period, each ISO dispatches internal generation so the total physical flow of power between regions matches (as closely as possible) the aggregate quantity of offers accepted by both ISOs;
4. Settlement. Market participants with accepted requests incur a financial obligation, as discussed below.

Each step is performed for both the day-ahead forward market and hour ahead ("real-time") trading, except that the delivery stage in Step 3 is omitted day-ahead.

There are many procedural details associated with each of these four steps, and they differ between the ISOs. Rather than elaborate on these details here, it is useful to consider the physical and financial obligations this transaction system entails, and the roles of the ISO and the market participant in making it work.

Physical and Financial Obligations: Who Does What?

Market participants refer to accepted offers to buy or sell across the interface between ISOs as *external transactions.* An external transaction is a binding financial arrangement between each ISO and the market participant. Although settlements are performed separately by each ISO, the market participant's net gain or loss on the transaction is ultimately this: It pays, or is paid, the difference in locational marginal prices (LMP) between each region, plus various fees. The difference is calculated for the delivery hours to which the transaction applies, and for each megawatt transacted.

For example: If the ISOs clear a market participant's offer to buy (export) from New York and sell (import) into New England in an upcoming hour, and the LMP is $40 per MWh in NYISO and $50 per MWh in ISO-NE during that hour, the participant's net gain is $50 – $40 = $10 for each MWh transacted (before fees).

It is important to note that transaction requests are submitted and accepted in advance of when the power flows. (So-called "real-time" transaction offers are due at least an hour in advance, for example.) This means that when a transaction is accepted, there is uncertainty about the LMPs at which it will settle. If, continuing the example, the real-time LMP in ISO-NE (where the participant sold) turns out to be $30 per MWh, then the participant has a net loss of $30 – $40 = –$10 per MWh (before fees). Thus a market participant can make or lose money on the external transaction.

Now consider physical delivery. Although real-time schedule requests are nominally 'physical' energy trades, the physical delivery obligation applies only to the two ISOs. That is, a market participant arranging an external transaction between New York and New England incurs no *physical* obligation by doing so. Excepting capacity market products, a participant submitting an external transaction need not supply generation to 'match' its buy or sell request—or have any physical assets at all.[6] If a market participant's external transaction offer is accepted, the market participant's only obligation is financial.

The distinction between financial and physical obligations is an important feature of market design for inter-regional trade. Market participants with external transactions do not dispatch resources to satisfy the interface schedule between NYISO and ISO-NE under the existing trading system, and they will not do so under either of the options presented in this report. Instead, the ISOs will continue to bear the obligation to determine the physical tie schedule by aggregating market offers, and to execute it using least-cost dispatch on each side of the border.

The Economic Purpose

What economic purpose is served by allowing a market participant to buy power in one region and sell it in the other? Fundamentally, this is a mechanism to converge the LMPs between two adjacent power networks. Here's why: After all transactions are submitted, the ISOs aggregate the accepted transactions into a net tie schedule across each interface. The net tie schedule determines the direction and magnitude of power

6 This contrasts with capacity imports, under which a market participant incurs a physical capacity availability obligation.

flows between regions that the ISOs seek to maintain over the upcoming hour. When the net tie schedule sends power from the lower-cost to the higher-cost region, the ISOs displace an expensive generation facility in one region with a less-expensive power source in the other region. This enables the ISOs to meet demand at lower total production cost, a central ISO objective.

Consistent with this objective, the ISOs' current market rules are designed to enable market participants to earn a profit when they buy and sell in a way that converges LMPs between regions. In general, market participants take a financial loss when they do the reverse (cause price divergence). This aligns private incentives for trade with the public's interest in minimizing total production costs.

While market participants have the incentive to execute efficient trades under the current system, the current system does not produce optimal results. This occurs because of shortcomings in the current trading system's design that impede price convergence. The inability of the current scheduling system to effectively converge prices is amply evident in the data that show price convergence remains limited. This is documented in detail in Part II.

Fortunately, the current trading system is not the only way to schedule power flows between regions. A key feature of today's system is that the two ISOs use market-based information to set the net interface schedule between regions. However, there are many alternative ways to use market-based information to determine interface schedules. The ISOs believe that two specific alternatives deserve careful consideration, as they would perform significantly better than the current system and overcome many of the documented problems. These alternatives are presented in Parts III and IV.

II. Problems: Evidence and Causes

Since at least 2003, market monitor Potomac Economics has expressed concern that the current inter-regional trade system fails to converge prices between ISOs.[7] The ISOs share the concern. Both the market monitor and the ISOs have recognized that inter-regional trade improvements must be prioritized in relation to other important market improvements.

Regional price differences that persist over many years are a symptom of underlying problems. Unless the transmission network is congested, price differences imply low-cost generation is used too little and high-cost generation is used too much. This runs counter to the ISOs' shared objective of meeting total demand at the lowest possible cost. It also implies loads are paying higher energy prices than necessary.

In this section, we examine data that reveal the extent of the problem. We then analyze the root causes that point to underlying flaws in the current trading system.

A. Economic Inefficiencies

To evaluate how well the current trading system serves its economic purpose, we first examine price and transmission data. Two central conclusions emerge. First, in most hours of the year, there is ample transmission capacity available to move additional power from the lower-cost ISO to the higher-cost ISO.

Second, the region with lower costs switches back and forth frequently—often reversing within each day. At the primary border between NYISO and ISO-NE, each region has the lower price about equally often over the course of the year. As a result, production costs in each region would be reduced if the transmission ties between them were scheduled more efficiently.

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[7] David Patton, *Coordinated Interchange Recommendations,* March 13, 2003 (Presentation to New England RTO Working Group).

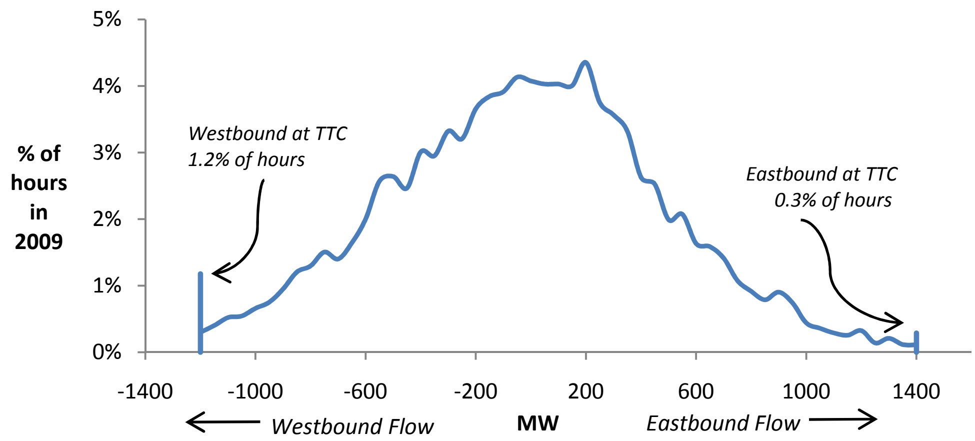

Figure II-1. Scheduled flows on the (NYN) interface between NYISO and ISO-NE in 2009.

TIE UTILIZATION

Is there unused transmission capacity across the interface between New York and New England? In brief, yes. This is evident in transmission operational data.

Figure II-1 shows the frequency distribution of hourly power flows across the primary interface (NYN) between NYISO and ISO-NE for 2009. In the figure, the height of the curve indicates the fraction of hours in 2009 in which directional flows equaled a particular MW level. For example, scheduled flows were 200 MW eastbound approximately 4% of the year.

Figure II-1 indicates that the primary interface (NYN) typically operates at far less than its total transmission capacity (TTC). For example, over seventy-five percent of the time scheduled and actual flows across the interface are between –600 MW and +700 MW (these values are half the normal westbound and eastbound normal capacities, respectively). So more than three-fourths of the year, the transmission interface operates at less than half its capacity.

We have also examined the same data for 2007 and 2008, and the results are substantively identical. The pattern shown in Figure II-1 has been stable for several years.

TIE CONGESTION

Congestion is Rare. The figure shows the primary NY-NE transmission interface is constrained very few hours per year. The height of the solid (blue) line at –1200 MW means the interface is at or near its nominal westbound total transfer capacity (TTC) about 1.2% of the year; similarly, the interface is at or near its nominal eastbound TTC of 1400 MW only 3/10ths of one percent per year.[8]

As a technical matter, the interface's operating capacity is occasionally de-rated for reliability reasons. The underlying transmission data indicate the interface was constrained at a de-rated MW limit approximately 1 percent of the hours in 2009.[9]

In sum, transmission capacity constraints did not bind on this interface 97% of the hours in 2009. As Figure II-1 makes clear, there is ample transmission capacity to move additional power between NYISO and ISO-NE across their primary interface.

IMPORTS/EXPORTS

Balanced Imports and Exports. A second point to note in Figure II-1 is that the frequency distribution of flows is centered at about zero. The actual average hourly flow across this interface in 2009 was 42 MW westbound. This means that across their largest interface, neither New York nor New England is predominantly an exporter to the other on an annual basis.

In addition, there is little parallel path (loop) flow across the AC transmission system between NYISO and ISO-NE. This is an important difference from the loop-flow transmission coordination issues that NYISO faces on its interfaces with other ISOs, and that are being actively addressed in NYISO's Broader Regional Markets initiative.[10]

INEFFICIENT TIE UNDER-SCHEDULING

It is important to emphasize that, standing alone, the data in Figure II-1 do not imply the transmission system is scheduled inefficiently. It indicates there is ample capacity to move additional power—but it does not show whether it would be economic to move additional power.

To determine whether the interface is inefficiently utilized, additional data are needed. Next we examine scheduled tie flows during hours when one ISO is operating higher-cost generation than the other, and the transmission interface between them is unconstrained.

8 In this report we characterize an interface as congested, or operating 'at or near' its TTC, if scheduled flows are at or within 2% of the TTC applicable at the time the schedule is finalized for the upcoming operating hour. Key conclusions in this report are not sensitive to expanding the 2% tolerance (this is evident in the low incidence of flows at levels near east- and westbound nominal TTC in Figure II-1).

9 There are other constraints on changes in transmission flows. In particular, pool ramp constraints bound on the interface (on either the NYISO or ISO-NE side) approximately 1000 hours in 2009. These constraints do not limit the *level* of scheduled and actual flows, but restrict *changes* in flows from one hour to the next.

10 New York ISO, *Report on Broader Regional Markets,* FERC Docket ER08-1281 (January 12, 2010).

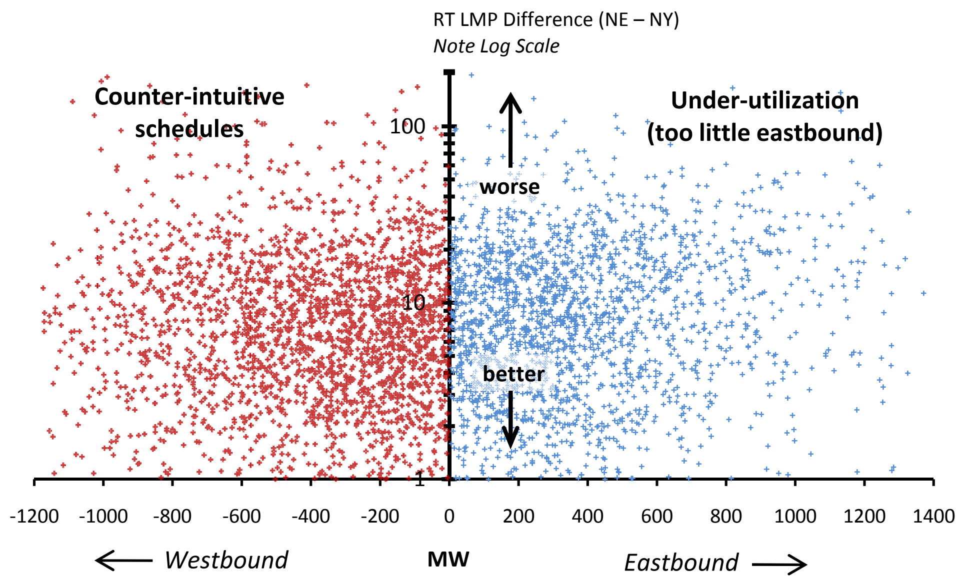

Figure II-2(a). Scheduled net tie flows and LMP differences across the primary interface (NYN) during hours in 2009 when (1) New England's LMP exceeds New York's LMP and (2) the interface TTC is not binding. Note the price difference on the vertical axis is in logarithmic scale. Prices are real-time hourly integrated LMPs for the external proxy buses (Sandy Pond and Roseton price nodes).

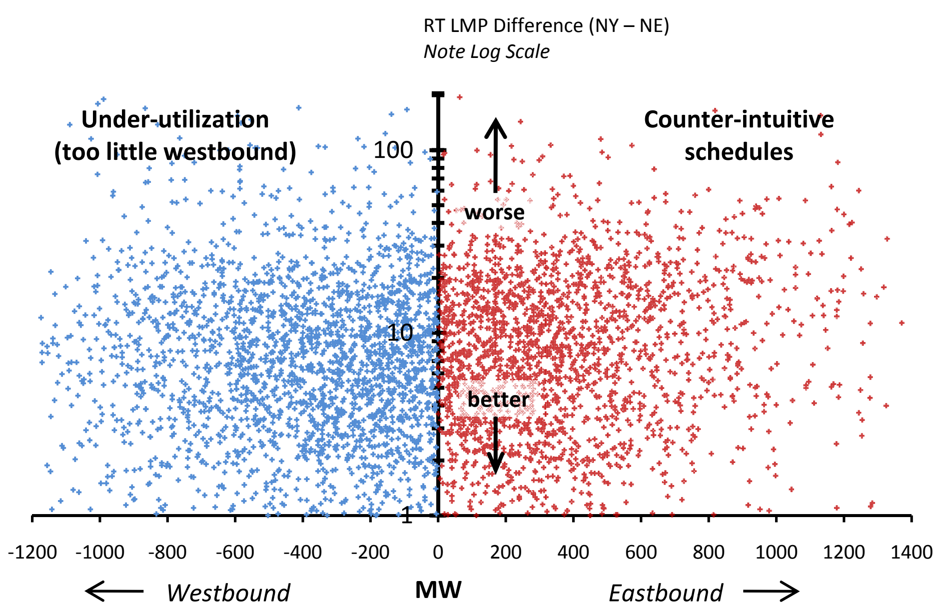

Figure II-2(b). Scheduled net tie flows and LMP differences across the primary interface (NYN) during hours in 2009 when the high-price region is reversed: (1) New York's LMP exceeds New England's LMP and (2) the interface TTC is not binding. The price difference on the vertical axis is reversed from (a), and in logarithmic scale.

We present separate charts for two situations: Hours when New England has higher prices, and hours when New York has higher prices. The first situation is shown in Figure II-2(a) (*top previous page*). Each dot in the scatter-plot represents an hour during 2009 when two conditions apply: (1) New England's RT LMP exceeds New York's RT LMP, and (2) the interface TTC is not binding.[11] This occurs about half of the year. The horizontal axis is the scheduled tie flow across the primary interface (NYN), and the vertical axis is the LMP *difference* between the two regions that hour (NE minus NY). Note the vertical axis is in logarithmic scale.

In the lower graph, Figure II-2(b) shows the situation during hours when (1) New York's RT LMP exceeds New England's RT LMP, and (2) the interface TTC is not binding. This occurs during the other half of the year. Note the vertical axis in the lower graph shows (the logarithm of) the price difference subtracted the other way, or NY minus NE.

The right-hand side of the top graph, Figure II-2(a), shows the hours when New England's price is higher and scheduled flows are eastbound (blue dots). This occurs 2141 hours, or about 24%, of the year in 2009. This is the economically correct direction when New England has higher prices: It displaces higher-cost generation with lower-cost generation from New York.

In the lower graph, Figure II-2(b), the left-hand panel shows hours when New York's price is higher and scheduled flows are westbound. This is the economically correct direction when New York has higher prices, as it substitutes lower-cost generation from New England for higher-cost generation New York.

UNDER-UTILIZATION

Even though trade is the economically correct direction about half the time, the data in the top-right and lower-left panels (blue points) imply the NYN interface is inefficiently under-utilized during these hours. Although flows are in the correct direction, the tie is unconstrained and the regions' LMPs remain far apart. The average price difference in these hours is $11.82 per MWh, and price differences exceeding $20 per MWh are not uncommon.

From the perspective of the ISOs that seek to operate the power grid in a least-cost manner, too little power is flowing in the correct direction more than 4000 hours per year. That is a true economic loss: One ISO is running higher-cost generation on the margin than the other, and society could save much of this difference if the transmission network was scheduled efficiently.

[11] All price data presented in this section are the 'border', or proxy bus, real-time hourly integrated LMPs for NYISO and ISO-NE (Sandy Pond and Roseton price nodes).

INTERPRETATION

The economic costs of under-scheduling have a useful visual interpretation. Consider Figure II-3. Here the black curve represents the generation supply offer stack in ISO 1, which is exporting. The blue curve represents the generation supply offer stack of importing ISO 2, shown here in *descending* bid-cost order. (In practice these supply curves have stair-step shapes, but they are drawn here as smooth curves for clarity).

In Figure II-3, the (red) shaded triangle represents the excess production costs incurred because the tie is under-utilized. If exporting ISO 1 increased production by the under-utilized amount, and importing ISO 2 reduced production accordingly, total costs would decrease. The savings is the difference in their supply curves over the range of this schedule change.

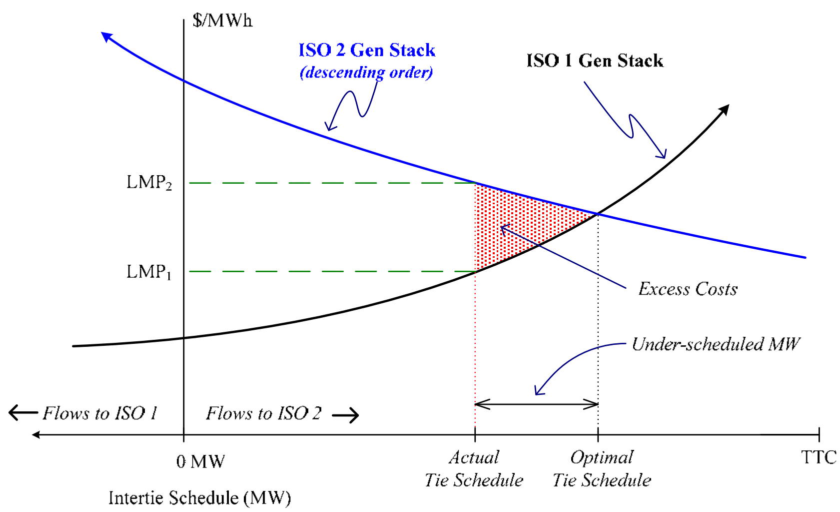

Figure II-3. The excess costs of tie under-utilization

In Figure II-3, which real ISO represents which curve? It can vary by hour. The top-right panel in Figure II-2(a) corresponds to the situation depicted in Figure II-3 with NYISO as ISO 1 (exporting) and ISO-NE as ISO 2 (importing). The bottom-left panel in Figure II-2(b) applies with the flows reversed, that is, for the situation in Figure II-3 with NYISO as ISO 2 (importing) and ISO-NE as ISO 1 (exporting).

Regardless of which direction the flows go, excess costs exist whenever the tie is under-utilized. About half the time it occurs, ISO-NE incurs the excess costs; the other half of the time, NYISO incurs the excess costs. Both ISOs' systems would operate more efficiently if these excess costs were reduced with more efficient scheduling.

COUNTER-INTUITIVE FLOW

The left-hand panel (red dots) in Figure II-2(a) and right-hand panel in II-2(b) illustrate a phenomenon known as *counter-intuitive flow* (or “wrong-way” flow). It happens a lot: Nearly half of the time that New England has higher-cost generation on the margin than New York, the net scheduled flow is *westbound* into New York. We see the same problem of counter-intuitive flow similarly often in Figure II-2(b), when New York has higher-cost generation on the margin.

IMPACT

Counter-intuitive flow has material adverse consequences. It means the net tie schedule is causing the exporting ISO to *increase* production from high-cost generation at the margin, and the importing ISO to *decrease* production from low-cost generation. This economically perverse outcome raises the total costs of serving demand, relative to a lower level of flows (that is, flows closer to zero). Total production costs would fall if flows were reduced (toward zero), up until the point where it caused the ISOs' re-dispatch to produce equal LMPs.

INTERPRETATION

To understand the economic impact of counter-intuitive flow, consider Figure II-4. This shows the supply curves drawn to illustrate a situation with counter-intuitive flow.

Here the actual tie schedule *exceeds* the optimal tie schedule. This forces the exporting ISO to incur higher generation costs (at the margin) than the importing ISO. The flows are “counter-intuitive” in this situation because the exporting ISO's price (LMP 1) exceeds the importing ISO's price (LMP 2); that is, flows are from the high-cost to the low-cost region *at the margin.*

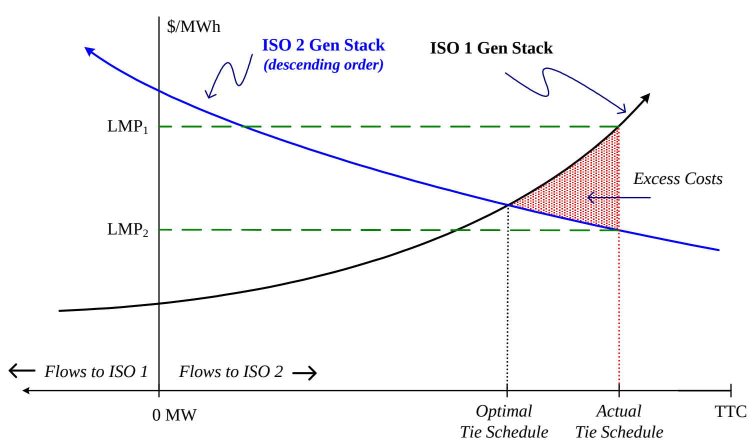

Figure II-4. Counter-intuitive flow creates excess costs

When counter-intuitive flows occur, there are excess costs. In principle, the solution to costly counter-intuitive flow is to reduce the net tie schedule (toward zero). If the tie schedule was reduced to the point where the ISO's LMPs are equal—the optimal tie schedule—then total costs would fall by the dollar amount represented by the (red) shaded triangle in Figure II-4.

WRONG WAY CASE

One other situation merits note. It is also possible for counter-intuitive flows to occur if the actual tie schedule is on the *opposite side of zero* from the optimal tie schedule. This can produce large excess costs, relative to the optimal tie schedule. In Figure II-2(a) and (b), the hours shown in the top-left and bottom-right panels (the red dots) include both the situation illustrated in Figure II-4, and any hours in which the schedule has the wrong direction entirely. Together, these counter-intuitive flows occur nearly half the year in 2009.

WHY IT OCCURS

In practice, counter-intuitive flow can occur for a number of different reasons. One problem is changes in system conditions that can lead LMPs to reverse between the time transactions are submitted and accepted (typically an hour before execution) and the time real-time prices are determined (almost two hours later). The inability of market participants or the ISOs to alter the net tie schedule in response to real-time price reversals can result in counter-intuitive flow.

The second problem is that market rules currently allow a market participant to submit schedule requests to intentionally 'buy high, sell low' across the interface. This directly produces counter-intuitive flows, unless a greater number of megawatts are accepted (or "clear") in the opposite direction.[12] We discuss this problem in greater detail in section II.C, below.

A third problem arises due to the uncertainly associated with real-time uplift (NCPC/BPGC) charges. If a market participant schedules a transaction day-ahead between regions, but the region with the lower costs reverses the next day operating day, the market participant may choose not to deviate from its day-ahead schedule in order to avoid real-time deviation (balancing) charges. This leads to counter-intuitive flow in real-time.

[12] Market participants point out they may intentionally submit counter-intuitive (high-to-low price) schedule requests to fulfill other contractual obligations. For example, ISO-NE's capacity import rules can require this, as may terms of certain renewable energy credits.

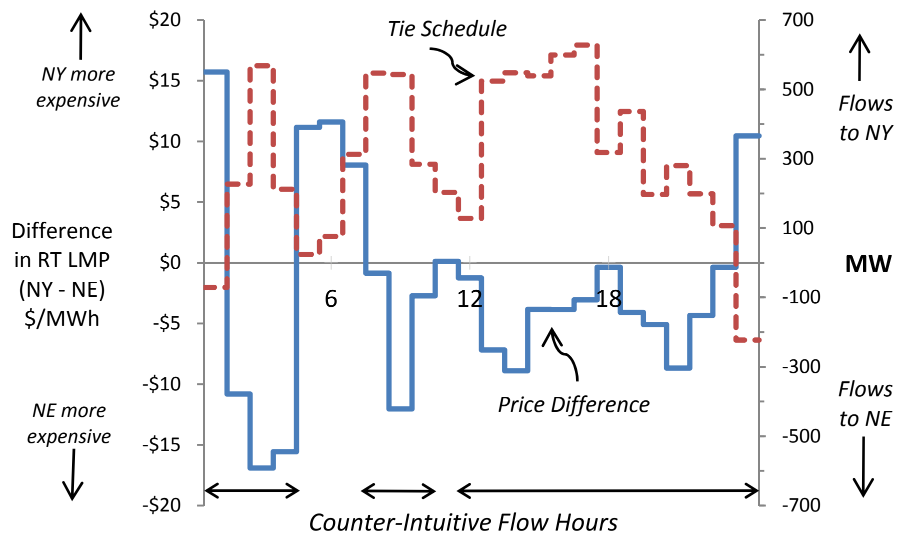

Figure II-5. Counter-intuitive schedules continue for hours on end (June 16, 2009)

EXAMPLE

Counter-intuitive flows are not only associated with rapid price reversals across the interface. They can, and do, persist for hours on end. Figure II-5 (*next page*) provides an example for one day (June 16, 2009). This was an ordinary operating day for both ISOs, with LMPs rising in their usual pattern that summer from overnight in the $10-20/MWh range to afternoon highs in the $40-50/MWh range.

The figure shows that from 2 AM until 11 PM, the net tie schedule (NYN) was westbound and ranged from near zero to 650 MW. However, for nearly all of these hours the LMP was *higher* on the New England side of the border. The counter-intuitive flow continues for hour after hour—20 hours in all that day. No participant submitted potentially profitable external transactions in the opposite direction and closed the price spread (possibly due to the risk of prices inverting, or due to the ISOs' transaction fees on external transactions).

This one-day example is by no means unique. As the prevalence of points in the red portions of Figure II-2(a) and (b) suggest, counter-intuitive flow occurs nearly half of the hours per year. There are many days, such as in Figure II-5, when counter-intuitive flow continues for long periods at a time.

A final point to note from Figures II-2(a) and (b) is that the fraction of hours with counter-intuitive flows is similar whether New England is the higher cost region (top graph) or New York is the higher cost region (lower graph). That means both regions stand to benefit from lower production costs under a system that produces more efficient scheduling and reduces counter-intuitive flow.

Balance of Prices

As the economic supply-curve depictions in Figures II-3 and II-4 suggest, the gains from more efficient scheduling depend on how often there are large price differences on either side of the border. The scatter-plots in Figure II-2(a) and (b) suggest this occurs a lot. Here we take a closer look at how often prices differ between the New York and New England sides of the interface.

Price Differences

Figure II-6 shows an annual duration curve for the *difference* in hourly real-time locational marginal prices between NYISO and ISO-NE in 2009. Reading the duration curve in the usual way, it indicates how often the NYISO price exceeds the ISO-NE price by a given amount (or more). For example, 20% of the time, NYISO's real-time price exceeded ISO-NE's by about $7 or more per MWh. This specific duration curve is for the price difference across the primary interface (NYN), and excludes hours in which the interface transmission capacity limit is binding (3% of hours).

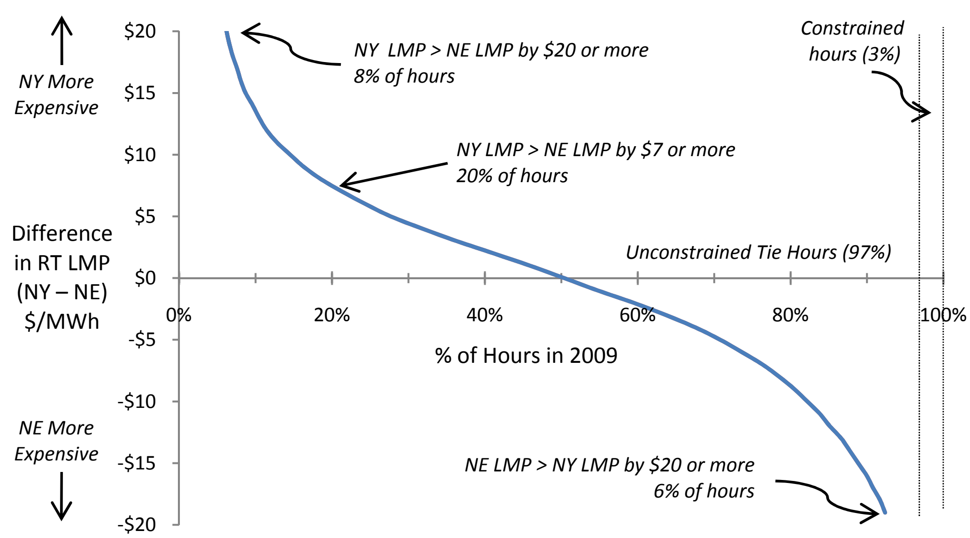

Figure II-6. Annual duration curve for the LMP difference across the NYN interface, 2009

Implications

Three observations are important. First, there are wide price differences in most hours. The price difference exceeds $5 per MWh (in absolute value) more than half of the year, and exceeds $10 per MWh (in absolute value) nearly one-third of the year. These are hours in which there is transmission capacity available to schedule additional transfers across the interface.

Second, the duration curve crosses the horizontal axis at the fifty percent mark. This means each region had the higher price at the primary interface (NYN) equally often.

Third, large price spreads occur with similar frequency in both directions. The figure reveals that in 8% of the hours in 2009, the NYISO price exceeded ISO-NE's price by $20 per MWh or more. At the opposite end of the duration curve, the data show that in 6% of the hours the ISO-NE price exceeded NYISO's price by $20 per MWh or more. The general symmetry of the price duration curve indicates the fraction of time in which one ISO has higher prices than the other is similar each way.

Taken together, these observations indicate that if an efficient interface scheduling system had been in place in 2009, the cost savings would accrue to both regions. The simulation results described in section II.B (below) confirm this.

VOLATILITY

Are inefficient tie schedules caused by volatile real-time price differences from hour to hour—and therefore hard for market participants to predict in advance? Yes, in part. The volatility of real-time price differences is evident using statistical indexes based on changes in the real-time price spread.

Figure II-7 plots the *50/50 Volatility Index* for the hourly real-time price difference between NYISO and ISO-NE at their border (the proxy bus price spread). Interpreting volatility indexes can be complicated, but the idea is simple: Larger values of the volatility index mean greater hour-to-hour changes in the price spread, in either direction.

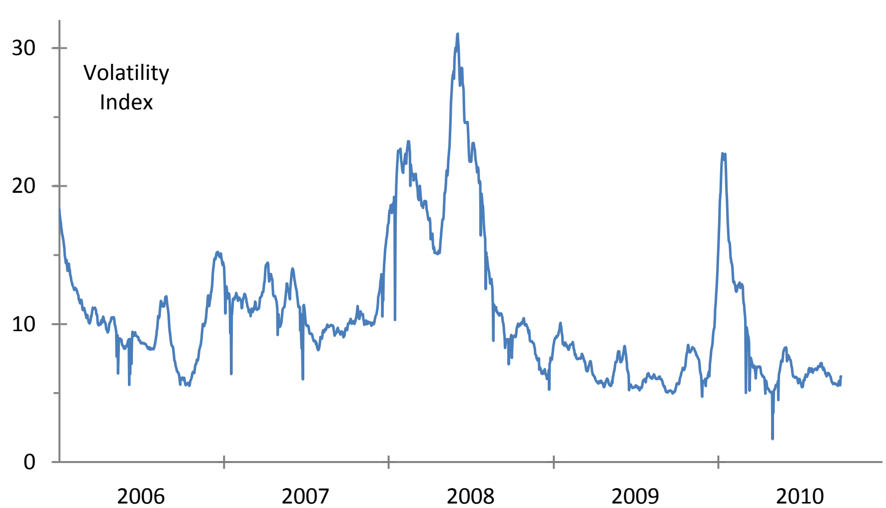

Figure II-7. Volatility of the hourly price spread between NY and NE over time.

This volatility index calculates the median change, from one hour to the next, of the (absolute) LMP spread across the NYN interface. The median is calculated over the last 30 days (720 hourly observations) on a rolling basis. For example, an index value of 10 means that half the time during the last 30 days, the price spread changed from one hour to the next by $10/MWh or more (either way); the other half of the time, the price spread changed by $10/MWh or less.

There are several key observations from Figure II-7. First and foremost, real-time price differences between regions can change greatly from one hour to the next. That contributes to tie under-scheduling and counter-intuitive flow. The current external transaction scheduling system produces inefficient net tie schedules—in effect, 'mistakes'—partly because system conditions change faster than the net tie schedule does.

This implies that to improve efficiency significantly, any tie scheduling system will need to update the net tie schedule at a higher frequency to react to changing system conditions. Higher frequency scheduling is an integral component of the solution options described in Parts III and IV.

Second, there is no clear evidence that price differences between the ISOs are becoming more volatile over the years. The high year is 2008, when fuel prices set record highs; the low year is 2009, when both fuel prices and power demand were low. This suggests that the benefits from a more efficient tie scheduling system would likely vary from year to year, depending on the underlying cost and demand drivers that determine how often the ISOs are operating on the steep portions of their supply curves.

In summary, the data on LMPs and transmission schedules examined here present a compelling case that the current external transaction system could be improved to serve its central economic purpose: To converge prices at the interface. That would reduce total system costs, and the prices paid by loads, in each region. We consider the economic benefits that may be realized from a more efficient scheduling system next.

B. Cost/Benefit Consequences

The prevalence of tie under-utilization and counter-intuitive flow means NYISO and ISO-NE are incurring higher production costs than necessary. How much would these costs be reduced if the interface between the two regions was scheduled efficiently?

To answer this question, NYISO and ISO-NE requested that Potomac Economics analyze each ISO's market and transmission data through 2010. The analysis also examines the changes in average LMPs in each region, and changes in loads' energy market expenditures, relative to the status quo. A detailed report will be forthcoming from Potomac Economics in early 2011; here we summarize prior estimates from Potomac Economics' *Annual Assessment* reports for New England and New York.[13]

Potomac's methodology employs a simulation model of production costs in each region, including the major transmission constraints internal to each ISO and between them. Using actual generation market offers and demand data, the model simulates the hourly generation re-dispatch that would converge prices, or bind the interface if that occurs first, between the two regions. It then calculates the change in production costs associated with this re-dispatch. Conceptually, this corresponds to estimating the size of the red excess cost triangles represented in Figures II-3 and II-4.[14]

One important cautionary note is in order. This method estimates "ideal" scheduling across the interface, as if the ISO's had a crystal ball revealing the next hour's LMP differences when setting the interface schedule between them. In reality, any feasible system will be subject to contingencies and unforeseen events that may limit its efficiency gains to less than this ideal. Accordingly, the results below are best viewed as the *potential* cost savings from an optimized tie scheduling system.

MAIN FINDINGS

Table II-1 summarizes the main findings. The estimated cumulative reduction in total production costs over the last five years totals $77 million dollars for the two regions combined. The annual figures vary modestly from year to year, being higher when fuel (principally natural gas) prices are high and lower when fuel costs decline, as occurred in 2009 and 2010.

Table II-1. Estimated Impact of Efficient Interface Scheduling

($ in millions)		Reduction in Loads' Expenditures		
Year	Reduction in Production Costs	Total	New England	New York
2010*	10	186	147	38
2009	10	125	68	57
2008	19	154	25	129
2007	21	199	22	177
2006	17	120	61	59
Cumulative	**77**	**784**	**323**	**460**

Note: 2010 data through October.
Sources: Potomac Economics, *Annual Assessment of the New England Markets* and *Annual Assessment of the New York Markets* for 2009 and updates.

[13] *Op cit.,* note 1, sections III and IV, respectively.
[14] Additional details can be found in Potomac Economics, *Annual Assessment,* §III (*op cit.*), and Potomac Economics, *Answers to Questions from Market Participants Regarding the 2008 State of the Market Report* (June 24, 2009).

The estimated reductions in energy expenditures by loads are an order of magnitude larger than the reductions in production costs. This occurs because increasing tie utilization by 200 MW reduces the production costs associated with that 200 MW, but it affects the LMPs for *all* load (unless limited by transmission constraints)—which may be 20,000 MW in each region at the time.

The estimated cumulative reduction in energy expenditures by loads if the interface was efficiently scheduled over the last five years totals over three quarters of a billion dollars. These savings vary by year and by region. During normal operating years, such as 2006 and 2009, the expenditure reductions to loads are quite similar in each region. During a year in which one ISO or the other has a greater number of price spikes, operating reserve shortages, or other adverse system conditions—as occurred in 2010, 2007, and 2006—the distribution of benefits skews toward the ISO experiencing more adverse system conditions. In this respect, efficient tie scheduling provides a degree of insurance to each region's loads that reduces the impact of price spikes.

Importantly, the data indicate that both regions' loads would experience lower costs in all years with efficient tie scheduling. The primary reason is that, in any particular hour, the lower-cost ISO tends to be operating on a flat portion of its supply curve, and the higher-cost ISO tends to be operating on a steeper portion of its supply curve. Sending additional megawatts from the low-cost to high-cost region tends to drop the price in the high-cost region a lot, but raise price in the low-cost region only a little. Because the region with lower costs varies from day to day and within each day, both New York and New England experience decreases in average LMPs on an annual basis.

Table II-2 summarizes this phenomenon using the data for 2010 (through October). It shows that with efficient tie scheduling that equalizes LMPs (up to transmission limits), the average LMP when New England is importing would fall by $7.32 per MWh, but when exporting would rise only about half as much, $3.75 per MWh. The results are similar for New York: Average LMP when it is importing would fall by $7.09, but when exporting would rise by only $3.89.

Table II-2. LMP Impacts of Efficient Interface Scheduling

Average Change in Hourly (Real-time) LMP, in $ per MWh		
	When Importing	When Exporting
New England	– 7.32	+ 3.75
New York	– 7.09	+ 3.89

Notes. 2010 data through October. *Source:* Potomac Economics

Two final results from Potomac's analysis merit note. First, the estimated change in total scheduled power flows between New York and New England with efficient tie schedules is modest: An increase of between 1 and 10%, in each direction, in most years. Second, the frequency of congestion across the primary interface remains only slight, increasing by 2-3 percentage points per year (up from the current 3 percent; see Figure II-1). This implies congestion is likely to remain infrequent across the primary interface between New York and New England.

SUMMARY

Taken altogether, the data support two main conclusions. First, the current external transaction system produces demonstrably inefficient outcomes. These inefficient outcomes cause excess production costs in each region, averaging in the low tens of millions of dollars annually. Second, loads pay for the inefficiencies of the current external transaction system. Their total energy expenditures would be on the order of one to two hundred million dollars lower annually—or perhaps half a million dollars *per day* lower—if the real-time inter-regional interchange system produced efficient tie schedules.

C. ANALYSIS OF ROOT CAUSES

The economic inefficiencies we observe with the current inter-regional trading system can be traced to three root causes. These root causes are important for understanding what problems must be solved, and why the solution options presented in Parts III and IV will produce substantially more efficient tie schedules than today's system.

The three root causes are:

1. *Latency Delay.* The time delay between when the tie is scheduled and when power flows, during which time system conditions and LMPs may change.

2. *Non-economic Clearing.* The ISOs make decisions about which tie schedule requests to accept without economic coordination, producing inefficient schedules.

3. *Transaction Costs.* The fees and charges levied by each ISO on external transactions serve as a disincentive to engage in trade, impeding price convergence and raising total system costs.

Each is addressed below.

THE LATENCY PROBLEM

"Latency" is the time delay between when (1) an ISO determines whether or not an external transaction request is economic (clears) and accepts it, and (2) the transaction's execution is complete. Under the current inter-regional trading system, the latency delay is nearly two hours for both NYISO and ISO-NE. Each ISO determines whether or not a “real-time” external transaction offer clears about an hour before the corresponding delivery hour, and this quantity remains fixed for the full delivery hour. This combination of hourly lead-time and the hourly duration-time are referred to an “hourly scheduling” system, although the latency delay is double that.

CONSEQUENCES

Latency delay causes excess costs for the system as a whole. Power system conditions can change from minute to minute, altering each ISO’s bid-based marginal generation cost. That can make a transaction that appeared economic when cleared an hour earlier actually uneconomic during the delivery hour.

The consequences of these *ex post* uneconomic transactions are evident in the data (section II.A) in two ways:

- *Tie under-utilization.* If the importing region’s LMP rises relative to the exporting region’s LMP after all transactions are accepted, imports are more valuable in real-time than the market anticipated. Even though power is flowing the ‘right’ way, *not enough* power is flowing the right way to minimize total system costs (*c.f.* Figure II-3).

- *Counter-intuitive flow.* If the importing region’s LMP falls relative to the exporting region’s LMP after all transactions are accepted, counter-intuitive flows may result. That inefficiently displaces low-cost generation in one ISO with high-cost generation in the other ISO at the margin, *increasing* total costs for the two regions overall (*c.f.* Figure II-4).

Latency delay is an economic problem because price information available to the ISO and to market participants more than an hour in advance is imperfect. This is evident in the volatility index (Figure II-6) above. The LMP data indicate that the region with the lower LMP (at the border) switched from one hour to the next over one-third of the time in 2009.

IMPLICATIONS

From the perspective of a market participant submitting an external transaction request, the latency problem creates financial risk. If the price difference between regions changes after an external transaction is accepted, the market participant can end up “buying high and selling low,” losing money on each megawatt scheduled. This risk poses a deterrent to submitting external transactions in the first place, exacerbating the tie under-scheduling problem.[15]

[15] Under certain conditions, each ISO compensates a market participant for financial losses on external transaction requests that clear an hour in advance but that incur a loss at real-time prices. In theory this may reduce the tie under-scheduling problem, but it will exacerbate the counter-intuitive flow. It also increases total ‘uplift’ charges ultimately paid by other market participants.

From the standpoint of economically sound market design, the best solution is an inter-regional interchange system that minimizes latency delay and the excess costs it creates. More concretely, resolving the latency problem requires:

1. Reducing the time lag between when the ISOs determine the aggregate net tie schedule and when the power actually flows; and
2. Enabling more frequent updating of the aggregate net tie schedule to reflect changes in system conditions and energy prices in real-time.

Satisfying each of these goals is a central design objective of both major solution options presented in Parts III and IV.

NON-ECONOMIC CLEARING

Under the current system, market participants submit separate external transaction requests to each ISO (*e.g.,* an offer to buy, or export, from ISO-NE is submitted only to ISO-NE, and the matching offer to sell, or import, in NYISO is submitted only to NYISO). There is no economic coordination between the ISOs when they set the aggregate net tie schedule. This absence of economic coordination when external transaction requests are accepted produces inefficient tie schedules, and raises total system costs. We explain how next.

CONCEPT

In an economically sound market design, an external transaction should be accepted, and increment the net tie schedule, if condition (A) is true:

(A) The importing region's expected LMP exceeds the exporting region's expected LMP.

(Assuming sufficient transmission capacity). This condition ensures low-cost generation displaces high-cost generation, lowering total production costs.

The current external transaction system does not verify condition (A), however. Instead, it checks two different conditions:

(B) The offer to buy (export) exceeds the exporting region's expected LMP;

(C) The offer to sell (import) is less than the importing region's expected LMP.

The ISO receiving the export-side schedule request checks (B), and the ISO receiving the import-side schedule request checks (C). If—and only if—both conditions are satisfied ("check out"), then the external request is cleared "to flow". These cleared transactions determine the net interface schedule during the requested delivery hour(s).

WHAT GOES WRONG?

The problem here is that conditions (B) and (C) do not imply condition (A). This means that transactions can, and are, routinely scheduled to flow that do not reduce total system costs. In fact, cleared transactions that do not satisfy condition (A) *raise* total system costs—to the detriment of everyone that buys power.

This problem is known as *non-economic clearing* because the necessary condition for a transaction to be economic—that is, condition (A)—is not checked by the ISOs before external transactions are cleared to flow.

What goes wrong in practice? The participant's offer to buy (export) from one ISO may clear at a *higher* price, while the offer to sell (import) in the other ISO clears at a *lower* price. Unless a greater number of megawatts are accepted (clear) in the opposite direction, this raises total costs for the system as a whole: High-cost generation in the exporting region is displacing low-cost generation in the importing region.

Note that this is a fundamentally different problem from latency. Here, there is no latency delay at all: The transaction is scheduled in the wrong way from the start. The root of the market design problem is that today's inter-regional interchange system checks (B) and (C), instead of checking all three conditions, before accepting transactions that determine the physical tie schedule.

PREVALENCE

The prevalence of this problem is indicated in Figures II-8(a) and II-8(b) (*next page*). The vertical axis shows the difference in the two ISO's *scheduling prices*, each of which is used by the ISO to accept its 'side' of the external transaction request (approximately 45 minutes before the delivery hour).[16] That acceptance process corresponds to the ISO checking condition (B) or (C) (depending whether it is exporting or importing, respectively). The horizontal axis is the net tie schedule across the primary interface (NYN), with each dot a separate hour. Any point in the top-left or lower-right panel (red dots) of the two figures has a higher expected LMP in the exporting ISO, and therefore fails condition (A).

There are a lot of hours that fail condition (A). The data in Figures II-8(a) and (b) cover all hours from July through December 2009. Of these, the ISOs are scheduling power from the high-to-low cost region (at the margin), raising expected total production costs, 44 percent of the time.[17] This is not because of latency; if the ISOs had these data in real time, they would have been able to see that the interchange scheduling system had produced an inefficient net tie schedule 45 minutes in advance.

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[16] NYISO's scheduling price is generated by its forward-looking real-time commitment algorithm at (approximately) 45 minutes before the hour. ISO-NE's scheduling price is determined separately, but at the same time, by software tools that evaluate the generation bid stack and expected dispatch rate during the delivery hour. Each ISO's scheduling price can be interpreted as the ISO's internal forecast of its LMP (at the border) during the next delivery hour.

[17] This phenomenon is most common when a market participant submits a price-based bid on the NYISO side of the border, and a "fixed bid" on the ISO-NE side of the border (a "fixed bid" is an offer to pay up $1000 per MWh to export, or to accept any price above zero to import). Any such bid-pair that clears on the NYISO side will also clear in ISO-NE, even if condition (A) fails.

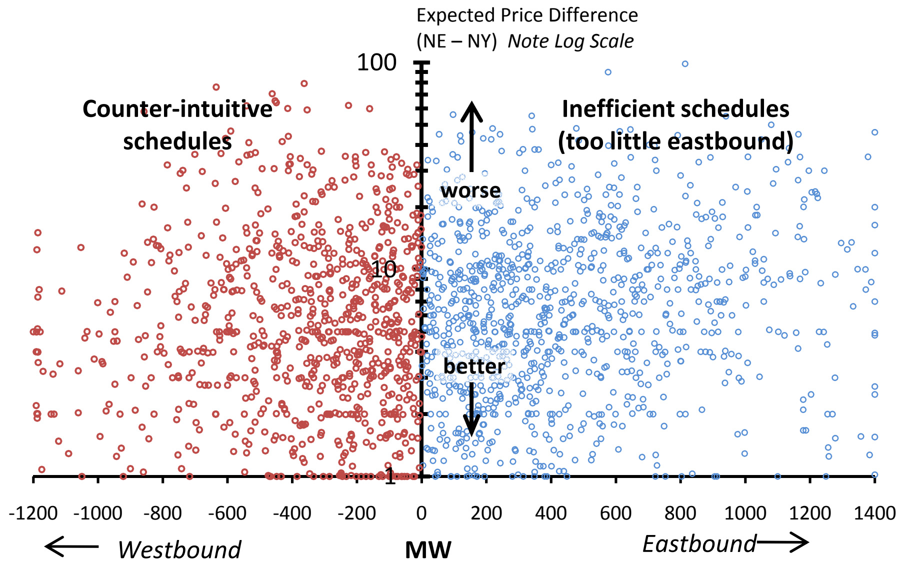

Figure II-8(a). Scheduled tie flow and the *expected* price difference across the primary interface (NYN) when New England's expected LMP exceeds New York's expected LMP during the upcoming schedule hour. Hourly data, July through December 2009. Note the price difference on the vertical axis is in logarithmic scale.

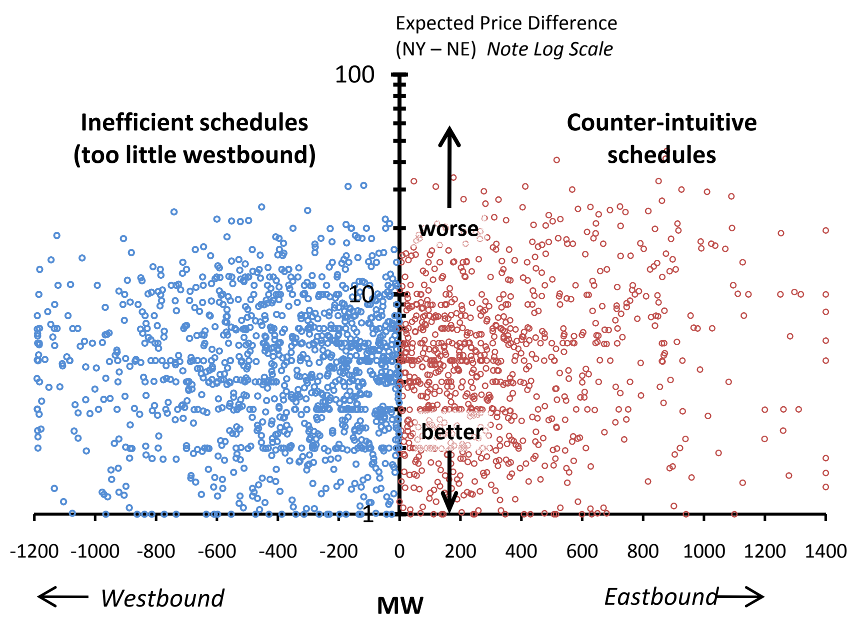

Figure II-8(b). Scheduled tie flows and *expected* price differences across the primary interface (NYN) when New York's expected LMP exceeds New England's expected LMP during the upcoming schedule hour. Hourly data, July through December 2009. Note the price difference is reversed from Figure II-8(a), and in logarithmic scale.

The upper-right and lower-left panels (blue dots) reveal an additional, different scheduling inefficiency. These panels show hours when the net interface schedule is in the direction that is expected to be economically correct (meaning, it satisfies condition (A)). The figure makes clear, however, that too little power is being scheduled to converge the LMPs most of these hours. That means total system costs are unnecessarily high: Trade fails to displace high-cost generation with additional lower-cost generation available from the exporting region. Of the remaining 56 percent of the hours, this situation occurs in almost all of them.

IMPLICATIONS

From the standpoint of economically sound market design, an efficient inter-regional interchange system should yield an interface schedule in the direction that satisfies condition (A). This would correct a fundamental market design flaw of the current inter-regional trading system that yields excess costs.

Correcting this fundamental flaw is a design objective satisfied by both of the major solution options presented in Parts III and IV.

TRANSACTION COSTS

The third root cause of inefficient net tie schedules is the transaction costs that market participants pay when they schedule external transactions. Both ISO-NE and NYISO impose a number of different fees and charges on external transactions. These include:

- An allocation to external transactions of general 'uplift' costs incurred by the ISO, on a per-megawatt basis.[18]
- Financial Impact Charges imposed by NYISO on import/export requests that fail the "check-out" process for reasons within the market participant's control.
- ISO scheduling fees paid by market participants on a per-megawatt hour basis, which for external transactions are levied by *both* ISOs.

In practice, the most consequential of these charges is likely the first. Real-time uplift averages a few dollars per megawatt on an annual basis, and is levied differently in NYISO and ISO-NE. However, it is highly variable from day to day, the charges are difficult to predict in advance, and there is no practical means for a market participant to hedge against them.

CONSEQUENCES

The allocation of these fees to external transactions reduces trade between regions and adversely impacts total production costs. The reason is straightforward: To cover the expected fees levied by the ISOs, a market participant will submit an external

[18] In NYISO, generators receive Bid Production Cost Guarantees (BPGC); in ISO-NE, this is known as Net Commitment Period Compensation (NCPC). To minimize unfamiliar acronyms, we use the generic term 'uplift' here.

transaction request when the expected price difference between regions exceeds the expected total fees. Put in financial terms, the participant will incorporate a margin, or "bid-ask spread", between the prices at which it is willing to buy and sell across the interface.

This rational behavior prevents price convergence between regions. System costs will be higher than necessary because the ties will tend to be under-utilized, relative to external transaction volumes if there were no per-megawatt transaction fees. In economic terms, transaction fees on external transactions act like a 'tax' that deters trade and distorts production costs upward.

How large is the distortion due to transaction costs? It is difficult to assess precisely, because the largest component—real-time uplift charges—is highly variable and creates risk that deters trade. On a monthly basis, real-time uplift charges average about $1 per MWh in NYISO and average between $1 and $4 per MWh in ISO-NE. ISO scheduling fees add another $1-2 per MWh or so (from both ISO combined). Together, these suggest a risk-neutral market participant would not find it profitable to schedule transactions that would drive prices between regions closer than perhaps $5 per MWh, maybe more.

IMPLICATIONS

Transaction fees can be allocated in a number of different ways. Allocating them in a way that prevents price convergence between regions means one region will tend to have higher-cost generation on the margin when lower-cost power is available and ample transmission capacity between them. This raises the cost of meeting total power demand.

While the allocation of uplift to external transactions in the real-time market 'saves' other market participants from paying these fees, this allocation may be a Pyrrhic victory that costs loads in the end. An example suggests why. An allocation of $5 per MWh on 1000 MW of external transactions in a particular hour means other market participants avoided $5,000 in ISO uplift charges. An efficient inter-regional interchange system would converge prices between regions, reducing the price spread by $5 per MWh.

What is that convergence potentially worth to loads? In electricity markets, when prices converge between regions the importing region's LMP will typically fall more than the exporting region's LMP rises. (See again Table II-2). For example, the LMP may fall by $3 per MWh in the importing region, and rise by $2 per MWh in the exporting region, to eliminate the $5 per MWh price spread between regions. Assuming both regions have equal loads of (say) 20 GWh at the time, the *net* savings to loads from eliminating the external transaction fees in this scenario would be at least $15,000 for that hour (20 GWh × ($3 – $2)/MWh, less a portion of the $5,000 in re-allocated fees).

The bottom line is that allocating uplift and other transaction fees to external transactions impedes price convergence between regions and raises system production costs. The magnitude of the benefits to loads from eliminating an uplift allocation to external transactions, in the form of lower LMPs due to greater inter-regional competition, could well outweigh the re-allocated costs.

III. Solution Option A: Tie Optimization

To solve the problem of inefficient interface schedules between ISO-NE and NYISO, the two ISOs established a joint design team to develop solution options and recommendations. In this section and the next, we present conceptual designs for two solution options: (A) Tie Optimization and (B) Coordinated Transaction Scheduling.

Either of these two options would be a major improvement over the status quo. Either option would eliminate much of the inefficiencies that result in tie under-scheduling and counter-intuitive flows. Relative to the current system, either option would yield lower production costs for both regions and significant savings for loads.

The two options we present are mutually exclusive, meaning the ISOs cannot implement both simultaneously. This is an operational constraint: The two systems employ different underlying mechanisms for using market-based information to determine the net interface schedule between regions. Of the two, the ISOs recommend the Tie Optimization option because it is the more efficient solution. This emphasis on efficiency reflects the ISOs' shared philosophy of using competitive wholesale markets to meet power demand at the lowest possible cost.

We describe the Tie Optimization option next. The Coordinated Transaction Scheduling option is described in Part IV.

A. Concept and Design Principles

Although market design details can be complex, the core idea of Tie Optimization is simple. It is this:

> The ISOs manage the transmission ties between them in the same way, or as close as possible to, the ISOs manage transmission internally.

In an important sense, Tie Optimization is not a new design. It is the same bid-based, security-constrained least cost dispatch logic that underlies the wholesale energy market administered by each ISO. This competitive market design applies to all internal nodes and internal transmission facilities today. Tie Optimization simply extends this market design to cover the pool transmission facilities that interconnect the ISOs.

In practice, this means three things:

- Optimizing physical transmission flows to minimize the total costs of meeting inter-regional demand, using market-based resource supply offers;
- Providing voluntary financial instruments to help market participants hedge price risk at the interface, for those who wish to do so;
- Eliminating procedural obligations that can require market participants to submit schedule requests in inefficient ways under the current system.

The first point addresses the inefficiently higher costs that result from the way physical transmission flows are scheduled across the interface today. Tie Optimization coordinates real-time energy dispatch across both ISOs' control areas to minimize total production costs. This is made possible because of advances in communications and information technology in recent years that enable the ISOs to implement a (near) joint energy dispatch without merging control rooms. We describe how this process works in more detail below (sections III.B and III.C).

The second and third elements in the list above provide market participants who currently "move power" across the interface with new options to meet their business needs. Only a subset of market participants actively engage in external transactions today, and their reasons for doing so are varied. Accordingly, the ISOs are interested in discussions with market participants about how to best accommodate their varied needs, in ways that are consistent with efficient operation of the inter-regional transmission network.

Core Design Principles

The ISOs developed the Tie Optimization option as a solution to the inefficiencies documented in Part II. The development of this option is guided by four core market design principles.

1. Efficiency. Tie Optimization is designed to schedule the transmission interface in the most efficient way, serving demand in both regions at the lowest possible production cost.
2. Market-Based Transmission Flows. The ISOs use competitive, market-based supply offers from market participants to determine the power system's dispatch. Least-cost dispatch determines all transmission schedules, within and between the two ISOs.
3. All Settlements at LMP. All energy flows across the interface are priced at the interface LMP. This facilitates market transparency, properly reveals and prices real-time congestion, and sends correct price signals to all market participants about the value of energy flowing between regions. Under either reform

option, there are no uplift debits or credits associated with inter-regional transmission flows.

4. ISOs Have No Financial Position in Markets. The ISOs do not directly participate in markets, and do not buy nor sell. Loads pay LMP for all power consumed, wherever the generation is located; generators receive the LMP at their locations, regardless of where the power goes. The ISOs will continue to act as independent settlement administrators for the payments to and from market participants. The same basic settlement procedures are used to settle cash flows on each ISO's internal energy market today.

Relation to VRD Discussions (2003-2005)

Back in the 2003-2005 period, ISO-NE, NYISO, and their stakeholders engaged in a discussion of "virtual regional dispatch" (VRD). VRD did not take the form of a fully developed market design proposal; discussions centered on (somewhat amorphous) proposals to more closely integrate power scheduling between ISOs.[19]

In 2005, the two ISOs took the concrete step of arranging an Inter-Hour Transaction Scheduling (ITS) experiment. The ITS experiment was operational in purpose, not economic. Reports indicate there was little impact on market prices, but no systematic economic analysis was conducted.[20] Neither the ISOs, nor their stakeholders, viewed further development as a priority given other pressing market development projects at the time.[21]

The financial arrangements under which the experiment was conducted raised concerns among some market participants. The experiment proceeded under special tariff provisions allowing the net costs to flow through to an ISO's operating expense.[22] Importantly, that will not occur under Tie Optimization. Instead, with Tie Optimization load pays generation for energy that flows across the interface in the same way that load pays generation for energy flows *within* an ISO's footprint. The ISOs act as settlement administrators for payments from loads to generation; the ISOs do not buy or sell power and take no financial position in the energy market.

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[19] See *Northeast ISOs Seams Resolution Report,* Item P18, October 8, 2010 (http://www.nyiso.com/public/webdocs/documents/regulatory/seams_issues/Seams_Closed.pdf#page=18).

[20] See *Intra-Hour Transaction Scheduling Between NYISO and ISO-NE: Report on the Pilot Tests Conducted on April 20-21, 2005* (http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2005/nov142005/a2_pilot1_report_2005_11_08clean.doc)

[21] See *ITS: How to Progress*, Joint Presentation to NYISO MSWG and ISO-NE Markets Committee (November 14, 2005) (http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2005/nov142005/a4_its_how_to_progress_2005_11_11.ppt)

[22] *Op cit.*, p. 3 (note 2).

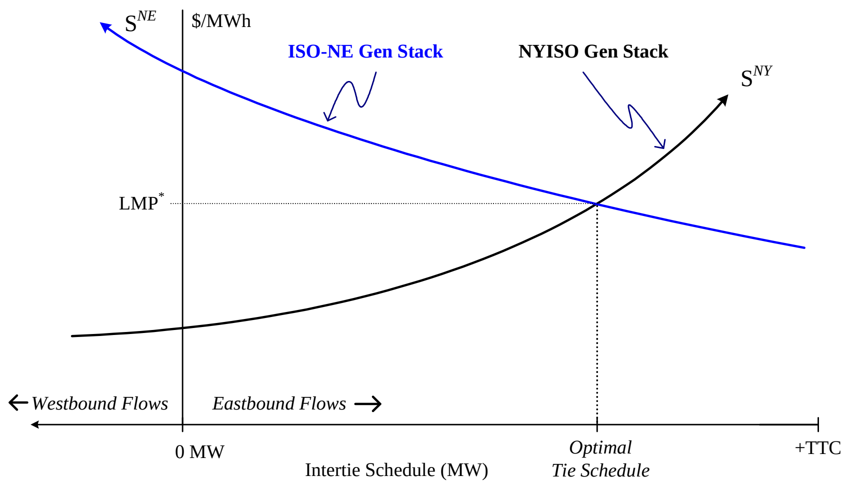

Figure III-1. The tie is scheduled efficiently when LMPs are equal

B. Economic Framework

A central difference between Tie Optimization and the current external transaction system is *which* market-based information the ISOs use to determine transmission schedules between regions. This section describes the economic logic of real-time Tie Optimization and its market foundations. Tools and process to enable a market participant to manage price risk are distinct solution elements, addressed in sections V and VI.

Although operational details of how the ISOs manage transmission can be intricate, the economic logic of Tie Optimization is conceptually simple. Consider Figure III-1. At a specific point in time, imagine the black curve represents the generation supply offer stack in one ISO (in this case, NYISO). This stack characterizes NYISO's incremental cost of delivering power at its side of the (NYN) interface. Similarly, the blue curve represents the generation supply offer stack of the other ISO (in this case, ISO-NE), shown here in *descending* cost order.[23]

The optimal tie schedule is the level of tie flow, in MW, that equates LMPs on each side of the border. In the figure, this is the point where the two supply stacks cross (labeled "Optimal Tie Schedule"). By setting the net aggregate tie flow at the level that equates

[23] More precisely, the supply curve is NYISO's incremental dispatch cost at the NYN interface proxy bus. Technically, each supply curve shown will incorporate all generation shift factors changes and internal transmission constraints that may bind and affect the proxy bus price over any segment of the range of admissible tie flows.

each ISO's LMP at the border, costs are minimized: There is no other way to allocate total generation, across all facilities in both regions, that yields lower total production costs.

As drawn in Figure III-1, at zero tie flow ISO-NE has higher costs than NYISO. Thus the optimal tie schedule is eastbound. The logic applies similarly in hours when NYISO has higher costs than ISO-NE (at zero tie flow). See Figure III-2. In this situation, the optimal tie schedule is westbound. Again, the optimal schedule is where the supply stacks cross.

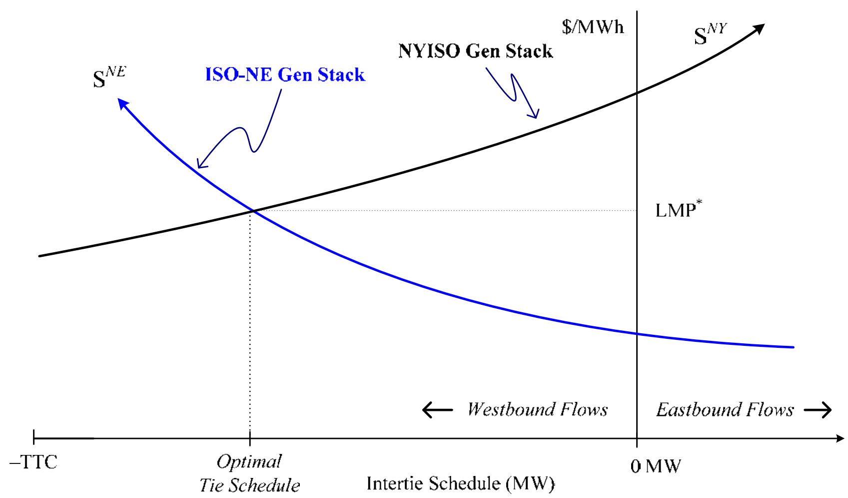

Figure III-2. Tie Optimization when the optimal schedule is westbound

The ISOs are able to determine this using their existing network models and market offer data by exchanging their exact interface (proxy bus) dispatch stack information in real-time. In effect, Tie Optimization amounts to pooling information on each ISOs' incremental bid-cost of supply, and decremental bid-cost of reduced supply, across the transmission interface. By pooling this information, the ISOs can determine how much to dispatch up and down on each side of the border to equate LMPs over the next dispatch interval. This prevents one ISO from operating higher cost generation (at the margin) than the other, whenever there is transmission capacity available to move power in the low-to-high cost direction.

WHO PAYS WHOM?

Figures III-1 and III-2 also reveal the basic settlement logic. For the moment, suppose there is no congestion nor losses. Load on the import side (whichever ISO that may be) pays the LMP at its locations. Generation on the export side is paid the LMP at its locations. If the LMPs are equal at the border, the (energy component of) LMP paid by load and paid to generation is the same.

To provide the appropriate cash flows, the ISOs—acting as settlement administrators—transfer specific funds coming from loads in the importing ISO to generation in the exporting ISO. The transfer is equal to the border LMP (or LMP* in Figures III-1 and III-2), times the tie schedule megawatts. In essence, the ISOs act as a joint settlement administrator for the appropriate payments from loads to generation across the interface.

Like internal dispatch today, there are additional settlement elements that arise due to congestion and marginal losses: LMPs at the border will not always equal internal node LMPs, nor always equal each other (e.g., if the tie is congested). Nevertheless, the basic settlement logic at the interface generalizes in the same way it is today applied to internal settlements for real-time congestion and marginal energy losses.

In sum, the central rationale for Tie Optimization is the same reason we use bid-based central dispatch today. A coordinated dispatch approach using both regions' market-based generation offers will produce the most efficient solution, minimizing both under-scheduling and counter-intuitive flows between regions.

C. Higher Frequency Scheduling

To minimize latency delays (see section II.C), it is desirable to set the tie schedule as close to real-time as possible, and to update it as frequently as system conditions change. This section describes the basic timing and information flows between ISOs in order to "cross the stacks" and implement higher frequency schedule (HFS) changes under Tie Optimization. HFS applies to real-time operations and to price formation in the real-time energy markets. (Day-ahead markets and interactions are addressed in Part V).

A substantively identical timing of information flows between the ISOs characterizes the Coordinated Transaction Scheduling option described in Part IV.

Overview

The ISOs propose to update the net interface schedule across each (AC) interface between ISO-NE and NYISO approximately 5-to-10 minutes before the energy flows. These schedules are (nominally) fixed for 15 minutes between each update. Within each 15 minute interval, each ISO will perform its internal dispatch.

The choice of 15 minute intervals is determined by current technology and operational considerations, not economic theory. With additional advances in technology, it may be possible to further shorten this interval. The key constraint is that Tie Optimization requires "pre-scheduling" passes of the unit dispatch system by each ISO, and an exchange of detailed solution information between ISOs after each pass. The resulting optimized net tie schedule is then incorporated into each ISO's next energy dispatch solution sent to generators.

The "pre-scheduling" process determining the net interface schedules is a look-ahead system, producing a binding net tie schedule for the upcoming tie schedule interval and 'advisory' net tie schedules for subsequent intervals. The look-ahead advisory net tie schedules preserve one important feature of today's hour-ahead tie scheduling system: It provides the system operators with information (expected net tie flows) that can be important for evaluating the near-term system trajectory (up to 60 minutes out) and making operational decisions over the next hour.

TIMELINE

The key steps determining the aggregate net tie schedule across a particular interface are best described using a timeline. This timeline is indicative, as exact times can vary during real-time operations and current dispatch timing conventions differ slightly between NYISO and ISO-NE.

For concreteness, we walk through the key steps and explanations in detail here. Times are in minutes.

T-20 *Step Pre-Schedule.* ISO-NE performs a set of "pre-scheduling" unit-dispatch system evaluations to evaluate the (bid-based) cost of incremental and decremental energy at the interface proxy bus at time T, T+15, T+30 and T+45.

This (parallel processed) evaluation determines the complete proxy-bus supply stack over the [-1200MW, +1400MW] transmission capacity of the interface. ISO-NE operational constraints on tie flows during these scheduling intervals may limit this range, and would be incorporated into the evaluation.

In the context of Figures III-1 and III-2, step *Pre-Schedule* determines ISO-NE's (blue) supply curve at the ISO-NE/NYISO border.

T-17 ISO-NE completes its supply stack evaluation. It passes the interface dispatch-rate schedule (proxy bus supply stack) to NYISO. Accompanying this information are any constraints indicated by ISO-NE operators governing interface flows over the upcoming schedule intervals.

T-15 *Step TieOpt.* NYISO integrates the ISO-NE interface dispatch-rate schedule into its RTD (real-time dispatch) optimization. The ISO-NE proxy-bus dispatch schedule is incorporated into RTD as the incremental cost incurred (by ISO-NE) to provide additional power across the interface into NYISO, and decremental cost avoided (by ISO-NE) by additional power flows across the interface into ISO-NE.

The RTD optimization determines each ISO's scheduled interface flow target for the 15 minute period starting at time T and 'advisory' tie schedule targets for the 15 minute periods starting at T+15, T+30 and T+45. If there are no binding constraints on the interface, each target equates NYISO's expected RT LMP at with ISO-NE's expected LMP.

In the context of Figure III-1 and III-2, step *TieOpt* implicitly determines NYISO's (black) supply curve at the border, and explicitly determines the quantity where the supply curves intersect (the optimized tie flow).

T-11 NYISO completes RTD optimization. It passes the optimized tie schedule MW to ISO-NE. Incorporated into the optimized tie schedules (for T, T+15, T+30 and T+45) are any constraints indicated by NYISO operators governing interface flows expected over the upcoming schedule intervals, as well as all constraints received from ISO-NE.

T-10 *Step RTD.* Each ISO performs its internal (real-time) dispatch, taking the optimized tie schedule MW for T as an input. The ramp profile is executed from T-5 to T+5. (This is the identical process the ISOs use today when they run RTD/UDS at 10 minutes before the top of the hour, since today's hourly tie schedule changes are executed over a nominal ramp interval from T-5 to T+5).

T-5 *Step Pre-Schedule update.* ISO-NE performs Step *Pre-Schedule* again, using updated system information as of T-55, to update its proxy-bus supply stack for T+15, T+30, T+45 and T+60.

Step TieOpt update. NYISO performs Step *TieOpt* again, using updated system information as of T and the results of ISO-NE's Step *Pre-Schedule* update. The *TieOpt* update produces new tie schedule targets for T+15, T+30, T+45 and T+60, sent to each ISO.

T+5 *Step RTD.* Each ISO performs its internal (real-time) dispatch as usual, now incorporating the updated optimized tie schedule target for T+15. The ramp profile is executed from T+10 to T+20.

T+10 *Step Pre-Schedule update* commences by ISO-NE.

T+15 *Step TieOpt* update commences by NYISO, producing new tie schedule targets for T+30, T+45, …..

T+20 *Step RTD,* taking the optimized tie schedule for T+30 as a constraint, with ramp profile executed from T+25 to T+35.

And so forth.

A few observations here are useful. First, the real-time dispatch steps that occur every five minutes are operationally the same as internal dispatch procedures today. It is the *inputs* that feed each ISO's internal real-time dispatch that change.

Tie Optimization 'feeds' the existing real-time dispatch a tie schedule target that is not fixed for an hour, as it is today. Instead, Tie Optimization feeds the existing real-time dispatch process with a sequence of tie schedule levels that are updated every 15 minutes. Each update also provides system operators with revised 'look-ahead' schedule information for each 15 minute interval, over the next 60 minutes.

In effect, with Tie Optimization the ISOs treat every 15-minute real-time point (e.g., the :00 minute, :15 minute, :30 minute, …) in the same way they dispatch today to meet the 'top of the hour' ramp window for hourly schedule changes. By doing so every 15 minutes, instead of only once per hour, the system produces a sequence of back-to-back ramp windows that is intended to smoothly adjust from one interval to the next.

This adjustment of the tie schedules is the key point. It enables the system to respond, in a more economically efficient way, to changes in the location of the lowest marginal-cost generation in either region. In effect, the dispatch process would use the market-based offers from all dispatchable resources—across both regions--to continually adjust the tie schedules, in near real-time, to re-balance production in the least-cost way.

ADDITIONAL OPERATIONAL OBSERVATIONS

In the HFS timeline, the Pre-Scheduling step is always performed by ISO-NE, and the Tie Optimization step is always performed by NYISO five minutes later. This sequencing of ISO actions builds on the comparative advantages of each ISO's existing technology infrastructure. ISO-NE's unit dispatch system accommodates a parallel-processing configuration that enables it to evaluate its supply stack over a range of candidate tie schedule levels in approximately the same amount of time needed to obtain a single unit dispatch solution. Thus, it is computationally efficient for ISO-NE to perform step *Pre-Schedule.* NYISO's current real-time dispatch produces generator set points for the next time interval (5 minutes), as well as 'advisory' generator set points for 15, 30, and 45 minutes out. Thus, by performing step *TieOpt,* NYISO can produce advisory tie schedules for these same future intervals within an existing software optimization system.

There are a number of additional implementation decisions with HFS. We briefly note several of these implementation decisions that may be of interest at this stage. The scope of analysis for these issues is more appropriate to an operational design proposal than this report's conceptual design analysis. Some of these implementation decisions may depend on pre-deployment performance testing and evaluation.

- *Proxy-Bus Granularity.* HFS may warrant evaluation of the appropriate granularity of the proxy-bus representations in network models and optimization, relative to current single-node proxy bus element for the NYN interface and separate proxy bus element for NNC (1385 line) used by each ISO.
- *SAR.* Because it may increase utilization of the tie lines significantly, Tie Optimization may impact the shared activation of reserves (SAR) between NYISO and ISO-NE. In principle, changes to the availability of reserves across

the border can be properly valued by the HFS algorithm, since both NYISO and ISO-NE have market-based reserve prices. This would result in the tie being scheduled to a lower level of capacity when the value of reserves across it exceeds the marginal value of energy across it.

- *Pool ramp constraints*. Priority rules may be needed to satisfy pool ramp limits across multiple interfaces simultaneously, if the scheduling 'lead time' varies across interface. This may be primarily an issue for the first-pass ISO (i.e., ISO-NE). For example, ISO-NE may need procedures to allocate pool ramp limits between the NYISO/ISO-NE, HQ/ISO-NE, and NBSO/ISO-NE interfaces during the top-of-the-hour ramp window.

D. What About Congestion?

Tie Optimization seeks to "cross the stacks" to equate each ISO's LMP on either side of the interface. However, at times there may be binding transmission constraints that prevent this. Although the economic logic of congestion pricing is the same whether it occurs across internal or across external transmission links, the external ties are administratively different. That presents two questions: First, if interface transmission constraints bind, how will the real-time congestion price across the interface be set? And second, who gets (and who pays) the congestion revenue? We address each in turn.

Real-Time Congestion Prices

Real-time congestion prices across an external interface under Tie Optimization mirror congestion pricing internally. Consider Figure III-3. As before, the black curve represents the generation supply offer stack in one ISO (in this case, NYISO), indicating its incremental cost of delivering power at its side of the (NYN) interface. Similarly, the blue curve represents the generation supply offer stack in the other ISO (in this case, ISO-NE), shown again in *descending* cost order.

In this situation, the point where the supply stacks cross exceeds the total transfer capability (TTC) of the interface. The optimal tie schedule is therefore limited to the TTC, and the HFS Tie Optimization process will set the tie schedule to that value.

The binding transmission constraint across the interface produces price separation between markets. Each ISO's LMP calculator will set the real-time LMP on its side of the interface as shown in Figure III-3. The cost of congestion across the tie is the difference between the importing and exporting LMPs in each region. In Figure III-3, the real-time congestion price is the difference $LMP^{NE} – LMP^{NY}$.

The logic applies just the same if the optimal tie schedule is transmission-constrained westbound in hours when New England has lower costs than New York.

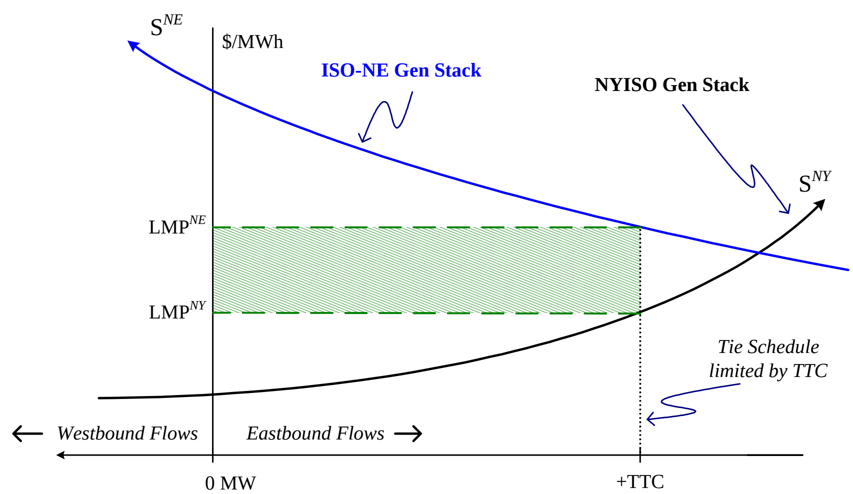

Figure III-3. Tie Optimization produces correct real-time congestion prices if total transmission capacity (TTC) limits tie flows between regions..

WHO PAYS WHAT?

There are a number of different ways to settle under the Tie Optimization solution option. For the sake of clarity, let's imagine—for the moment—that all energy is transacted in the real-time market. (This avoids the need to track deviations from day-ahead market positions, an issue considered in detail in Part V).

As usual, all payments are made between loads and generation, with the ISOs acting as settlement administrators. Load on the import side (in this case, ISO-NE) pays the LMP at its internal locations. Absent internal congestion (and ignoring losses), this is the same price paid to generation in the importing ISO. However, in the importing ISO there is less generation than load—the difference being the imported megawatts. That means the importing ISO receives more energy market revenue from its loads than it pays out to internal generation.

Where does the excess revenue go? Two places. Part of it must be paid to generation in the exporting ISO. As usual, generation in the exporting ISO is paid the LMP at its location. This is LMP^{NY} in Figure III-3 (absent internal congestion and ignoring losses). Acting as joint settlement administrators, the two ISOs transfer funds debited from importing-side loads to the credit of generation in the exporting ISO. This transfer equals the tie flow MW times the LMP on the exporting side of the interface (LMP^{NY} in Figure III-3).

Congestion Rent

Then there's the second part: When there is congestion, like in Figure III-3, there is a surplus left over. The amount left over is the *congestion rent*. In the figure, this is the shaded green area. It equals the congestion price across the interface times the (constrained) tie schedule MW.

What happens with the congestion rent? In practice, the congestion rent accrues (primarily) in the day-ahead market, where most energy is transacted, not in the real-time market. This provides the revenue stream necessary to fund risk-management products (FTR/TCC) across the transmission interface between regions.

Precisely how day-ahead congestion revenue accrues across an external interface requires a discussion of day-ahead markets and how they interact with congestion pricing of real-time flows. Day-ahead markets and settlements are similar under both the Tie Optimization and CTS solution options. Thus, we defer the details to Part V below, and explain the CTS option for real-time scheduling first.

The important point to note here is that the day-ahead settlement process does not change the basic economics of congestion pricing, or that loads must pay generation the appropriate LMP for power exported across the interface to serve them. The ISOs' role as joint settlement administrators for power flows between regions ensures the appropriate payments are made, and congestion revenue is accrued properly.

IV. Solution Option B: Coordinated Transaction Scheduling

A. Concept and Design Principles

The second solution option is a package of external transaction enhancements called *coordinated transaction scheduling* (CTS). The CTS has four major elements:

- High frequency scheduling (HFS) across external interfaces;
- Elimination of charges/credits on external transactions that deter trade;
- A simplified bid format, called an *interface bid*, for real-time scheduling; and
- Coordinated acceptance of bids by the ISOs, using an improved clearing rule.

The first two of these elements are substantively the same as the Tie Optimization option. The second two of these elements differ.

The core philosophy of the CTS is that the ISOs will determine the schedule across the (AC) interfaces between NYISO and ISO-NE using external transaction offers. Like the current external transaction system, under CTS the ISOs will use two sets of market-based offers to set the tie schedule: (1) participants' external transaction offers to buy and sell across the interface, cleared against (2) the real-time generation supply stacks in each region. However, the structure of the external transaction bid format, and how it clears, differs between CTS and the existing inter-regional trading system. These differences are designed to solve the root causes of the current system's inefficiencies, as explained in section II.C.

The CTS solution option differs from the Tie Optimization solution option in a broad way. Conceptually, the CTS is more like the current external transaction system than Tie Optimization: CTS retains a role for external transaction offers to determine tie schedules and real-time LMPs. In contrast, the Tie Optimization option looks like the least-cost economic dispatch process used internally by each ISO: It relies on only the bid-based supply offers from generators (along with load information) to determine real-time LMPs and all transmission flows.

Core Design Principles

The core design principles governing CTS are the same as those for Tie Optimization. The differences arise in how these design principles are applied.

In brief, the principles are four:

1. Improved Efficiency. The CTS is designed to operate the transmission interface more efficiently than the current inter-regional trading system, meeting the total power demand of both regions at lower cost than today.
2. Market-Based Transmission Flows. The ISOs use competitive, market-based supply offers from market participants to determine the power system's dispatch and net external tie schedule.
3. All Settlements at LMP. All energy flows between regions are priced at LMP. This facilitates market transparency and prices congestion across the interface. Under either reform option, there are no uplift debits or credits associated with inter-regional transmission flows.
4. ISOs Have No Financial Position in Markets. The ISOs do not directly participate in markets, and do not buy nor sell. Loads pay LMP for all power consumed, wherever the generation is located; generators receive the LMP at their locations, regardless of where the power goes. The ISOs will continue to act as independent settlement administrators for the payments to and from market participants.

B. Economic Framework

Two central elements of the CTS are the simplified bid format for real-time external transactions, and the clearing rule used to determine the net tie schedule with these bids. We address each in turn.

The Interface Bid Format

An *interface bid* is a unified transaction to buy and sell power simultaneously on each side of the interface. It settles at the real-time price difference. For example, an interface bid across the NYN interface is an offer to buy at the proxy bus on one side of this interface, and sell on the other.

Mechanically, an interface bid consists of three numbers: A price, a direction, and a quantity. The price indicates the minimum expected price difference between the two nodes that the participant is willing to accept. The direction indicates at which proxy bus the participant wants to buy, and at which it wants to sell. The quantity indicates how many megawatts the participant is willing to transact. If the interface bid is accepted (i.e., clears), the participant is paid the real-time price difference between the two nodes.

Like external transactions today, a market participant that submits an interface bid incurs no physical delivery obligation. All interface bids settle financially. From the ISOs' perspective, interface bids are simply a market-based device with which the ISOs determine the real-time net tie schedule between ISO-NE and NYISO.

Determining the Tie Schedule

Under CTS, a market participant submits an interface bid to either ISO. All bids are pooled by the two ISOs, who apply a coordinated acceptance (clearing) process that determines the net tie schedule.

The economic logic of this process is simplest to convey graphically. Consider Figure IV-1. At a specific point in time, imagine the black curve represents the generation supply offer stack in one ISO (in this case, NYISO). This stack characterizes the incremental cost of delivering power at its side of the (NYN) interface.[24] Similarly, the blue curve represents the generation supply offer stack of the other ISO (in this case, ISO-NE), shown here in *descending* cost order.

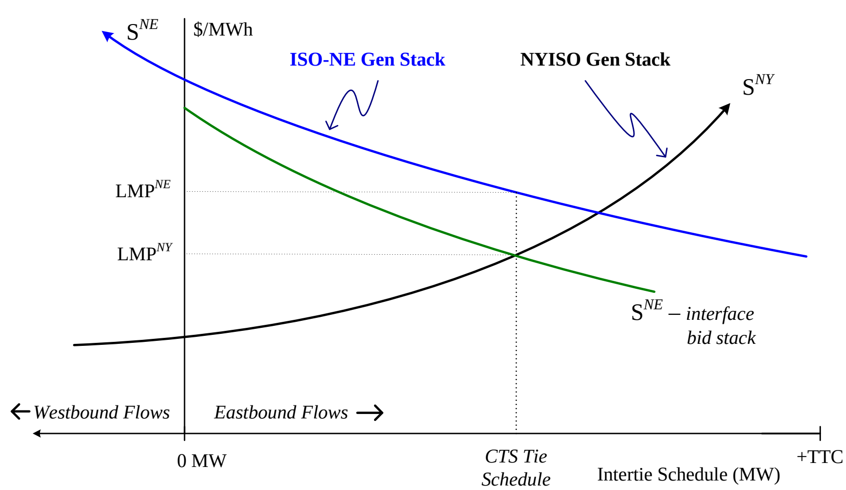

Figure IV-1. Determining the tie schedule using interface bids

[24] More precisely, the supply curve is NYISO's incremental dispatch cost at the NYN interface proxy bus. Like the Tie Optimization option, each supply curve shown will incorporate all generation shift factors changes and internal transmission constraints that may bind and affect the proxy bus price over any segment of the range of admissible tie flows.

CLEARING RULE

Unlike Tie Optimization, the ISOs will not automatically set the net tie schedule where the ISOs' generation supply stacks intersect. Instead, they will modify the supply stacks by simultaneously clearing the interface bids. The clearing rule is: An interface bid is accepted if the offered price is less than the expected LMP difference across the interface at the time the ISOs set the interface schedule.

How would the ISOs implement this rule? Mechanically, it takes three steps. First, the ISOs must assemble the total *interface bid stack.* Imagine taking the set of all interface bids indicating the same direction (say, eastbound). These bids are stacked, from lowest to highest price, to create their own 'supply curve'.

Second, we modify the expected generation supply curve of ISO-NE by *subtracting* the (eastbound) interface bid supply curve. In Figure IV-1, the result is depicted as the descending (green) curve. The CTS interface schedule is then set where the green curve intersects the NYISO's expected generation supply stack. All interface bids to the left of the CTS tie schedule are accepted; all interface bids to the right of the CTS tie schedule are not.

As drawn in Figure IV-1, at zero tie flow ISO-NE has higher costs than NYISO. Thus the tie schedule is eastbound. The logic applies similarly in hours when NYISO has higher costs than ISO-NE at zero flow. See Figure IV-2. Here the ISO's assemble the interface bid stack for all offers in the *westbound* direction, and *add* it to ISO-NE's generation supply stack. Again, the CTS tie schedule is set where the marginal interface bid equals the difference in LMPs across the interface.

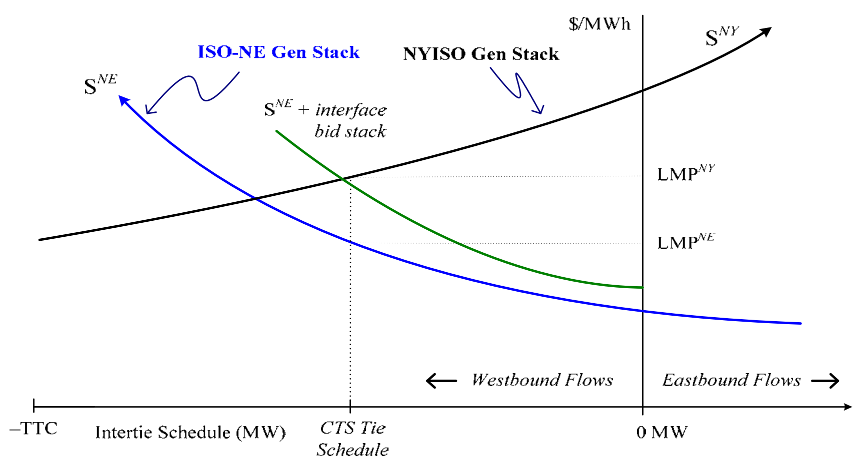

Figure IV-2. Determining a westbound CTS tie schedule

WHO PAYS WHOM?

Figures IV-1 and IV-2 reveal the basic settlement logic. For the moment, suppose there is no congestion, nor losses. Load on the import side (whichever ISO that may be) pays the LMP at its locations. In the importing region, internal generation is paid the same LMP. However, there is less generation than load in the importing ISO, so the importing ISO receives more revenue from load than it pays to its internal generation.

Where does the excess revenue go? It is paid to the market participants whose interface bids cleared. In this sense, participants with accepted interface bids are selling power to the importing region's loads.

The exporting ISO's settlement logic is symmetric. All generation is paid the LMP at its location. However, there is more generation than load in the exporting ISO. The market participants whose interface bids cleared cover the difference: They pay the exporting region's LMP for each MW cleared at the interface. In this sense, participants with accepted interface bids are buying power supplied by the exporting region's generation.

Like internal dispatch today, there are additional settlement elements that arise due to congestion and marginal losses: LMPs at the border will not always equal internal node LMPs, and the tie may be congested. Nevertheless, the basic settlement logic across the interface generalizes in straightforward way. We go through the settlement details, including day-ahead market interactions, in Part V.

EFFICIENCY

Figures IV-1 and IV-2 show situations without transmission capacity limitations, and reveal that CTS does not equate expected locational marginal prices on each side of the interface. The expected LMP in the importing region is higher than the LMP in the exporting region (unless the last accepted interface bid price is zero). As a result, the CTS interface schedule megawatts will be less than the interface schedule set by Tie Optimization (section III.B) when interface capacity is not limited. In theory, this means the CTS process is less efficient than Tie Optimization: If expected prices do not converge completely, one ISO continues to operate higher-cost generation that could be displaced by lower-cost generation from the other region—but is not.

A key property of the CTS bid format and clearing rule is that it solves the *non-economic clearing* problem that is a root cause of scheduling inefficiencies today (section II.C). The clearing rule ensures that, if a transaction is accepted, the expected price in the importing ISO is higher than the expected price in the exporting ISO. In the terminology of section II.C, the CTS clearing rule always satisfies condition (A). That ensures the interface schedule will never be set to flow in the wrong direction at the time the schedule is evaluated.

There is a similarity and a difference between the CTS option and the Tie Optimization in this regard. In Section II.C (Figure II-8), we showed that the current trading system frequently produces counter-intuitive schedules, and frequently exhibits under-utilization, at the time the tie is scheduled. Both the CTS option and the Tie

Optimization option completely solve the *first* of these two problems: By ensuring the importing region's LMP is at least as large as the exporting region's LMP, both options preclude interface schedules that are counter-intuitive (cost-increasing) at the time scheduled.

However, the two options differ with respect to tie-underutilization. Tie Optimization converges expected LMPs when the schedules are set, while the CTS leaves the importing ISO's LMP higher than the exporting ISO's LMP (unless the marginal interface bid is zero). That means the interface would be under-scheduled relative to the (efficient) level that minimizes total production costs.

C. Mechanics: HFS and Submission Timing

Both the Tie Optimization and the CTS solution options share the same higher-frequency scheduling (HFS) system. Under CTS and Tie Optimization, the ISOs require the same information on one another's current bid stack at the border, as indicated in Figures IV-1 and IV-2, to determine the tie schedule. Mechanically, the only modification to HFS between Tie Optimization and CTS is that the interface bid stack is added to, or subtracted from, ISO-NE's generation bid stack before the interface schedule is calculated.

The ISOs anticipate that the precise timing of information flows between NYISO and ISO-NE to implement HFS would be the same under either option. Accordingly, we refer the reader to section III.C for the indicative timeline and individual steps.

Interface bid Submission

As noted above, interface bids are pooled and conveyed to both ISOs. To do so, the ISOs anticipate developing a common bid submission platform for market participants submitting interface bids. The platform would provide a one-stop, fully-automated bid submission and validation tool, eliminating today's cumbersome submission procedures. In addition, the common submission platform would eliminate 'fail to check-out' outcomes, an inefficient source of financial risk for market participants submitting external transaction requests today.

One important element under CTS is the timing of interface bid submission. Current external transaction rules require schedule offer requests to be submitted 75 minutes before the delivery hour on the NYISO side, and 60 minutes on the ISO-NE side. This will need to be a single point in time, since all bids would be submitted to a common portal. The ISOs anticipate the bid time under CTS will remain 75 minutes in advance of the start of the delivery period to which the interface bid applies. This is to accommodate the look-ahead information needs of the ISOs dispatch and commitment systems, which assess changes in physical tie schedules 75 minutes forward as an input into generation dispatch and real-time commitment optimization.

D. What About Congestion?

At times, there may be binding transmission constraints that prevent the CTS clearing rule from setting the LMP difference across the interface equal to the marginal interface bid. The CTS addresses this using a modified congestion pricing rule that differs from internal congestion pricing.

CTS Congestion Cost

Under CTS, real-time congestion pricing across the interface has an additional element not applicable to pricing across *internal* transmission links. The additional element is the marginal interface bid. The payment made to each accepted interface bidder reduces the expected congestion revenue that accrues under CTS, relative to congestion pricing under Tie Optimization or between internal network nodes.

To illustrate the difference, consider Figure IV-3. As before, the black curve represents the generation supply offer stack in one ISO (in this case, NYISO), indicating its incremental cost of delivering energy to its side of the interface. Similarly, the blue curve represents the generation supply offer stack in the other ISO (in this case, ISO-NE) on its side of the interface, shown again in *descending* cost order.

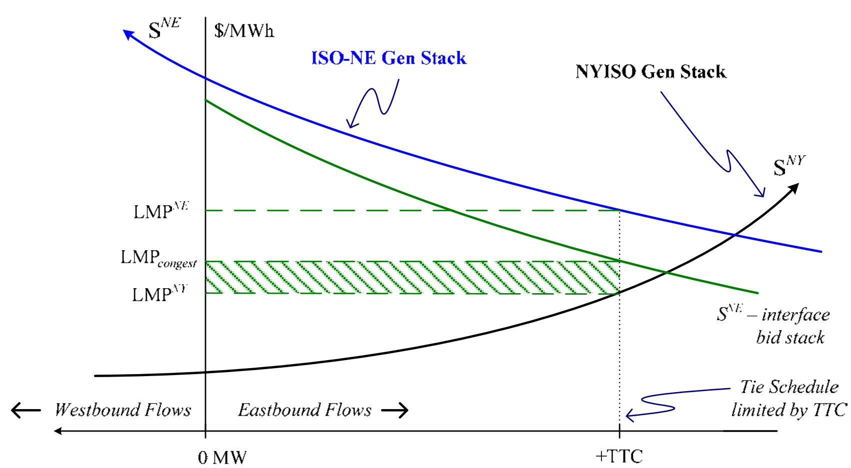

Figure IV-3. Payments to interface bids reduce the amount of congestion revenue collected if the tie's transmission capacity is binding.

In this situation, the total transfer capability (TTC) of the interface is less than the tie schedule that CTS would normally set—where the last accepted interface bid equals the difference between the two ISO's generation stacks. The tie schedule is therefore limited to the TTC, and the HFS process will set the tie schedule to that value.

CONGESTION RENT

The binding transmission constraint across the tie ensures price separation between markets. For the importing region, the importing ISO's LMP calculator will set the real-time LMP on its side of the interface equal to its marginal cost of energy delivered to the interface. This is shown as LMP^{NE} in Figure IV-3. At all internal nodes in the importing ISO (here, ISO-NE), this is the real-time LMP paid by loads and paid to generation (absent internal congestion and losses).

For the exporting region, there is a lower real-time (proxy bus) LMP equal its marginal cost of energy delivered to the interface. This is shown as LMP^{NY} in Figure IV-3. In the absence of any internal congestion (or losses), this is the real-time LMP paid by loads and paid to generation at all internal nodes in the exporting ISO (here, NYISO).

In Figure IV-3, there is a congestion price for energy delivered across the constrained interface. The congestion price is where the modified congestion price rule applies. As drawn in Figure IV-3, the importing ISO credits each accepted interface bid at a price equal to its real-time internal LMP, or LMP^{NE} in Figure IV-3. The exporting ISO debits each accepted interface bid at a price equal to its real-time LMP plus the congestion price, or $LMP_{congest}$ in Figure IV-3.

In this way, the congestion rent equals the shaded (green) box in Figure IV-3. The (real-time) congestion price under CTS is the difference between each ISO's marginal cost of delivering energy to the interface, less the price of the last accepted interface bid.

What happens with the congestion revenue collected under CTS? In implementation, the ISOs propose to use a modified settlement procedure from that indicated in Figure IV-3. The modification produces the same congestion rent and payments to interface bids. However, the modification allocates the congestion revenue in equal measure to the existing congestion revenue funds administered by each ISO. The precise settlement method is described in Part V, next.

In addition, under both Tie Optimization and CTS congestion revenue would accrue (primarily) in the day-ahead market—where most energy is transacted—not in the real-time market. This provides the revenue stream necessary for each ISO to fund risk-management products (TCC/FTR) across transmission interfaces between regions. We describe the structure and funding of each ISO's TCC/FTRs for the interface in Part VI.

V. DAY-AHEAD MARKETS AND INTERACTIONS

The Tie Optimization and the CTS options apply to the determination of inter-regional energy interchange in real-time. This report does not propose to apply either option to the day-ahead markets. Each ISO will continue to operate separate day-ahead markets, with separately-scheduled external transactions. However, there are important interactions between each ISO's day-ahead market and the real-time prices and interface schedules under an economic coordination system like Tie Optimization or CTS.

In this section we explain how each ISO's day-ahead market interacts with the real-time market under the Tie Optimization and CTS options, including the treatment of day-ahead external transaction offers and settlement procedures.

A. DAY-AHEAD MARKET ISSUES

There are two reasons why the solution options presented above focus on real-time, as opposed to day-ahead, interface schedules. First, to solve the problems documented in section II, the interface schedule must be coordinated efficiently in real-time. If the scheduling process does not produce price convergence in real-time (up to congestion), the ISOs are incurring higher production costs than necessary.

Second, close coordination of ISO-NE's and NYISO's day-ahead markets has less certain incremental benefits. At present, the ISOs' day-ahead markets are *asynchronous:* They operate during non-overlapping time periods prior to the operating day. In NYISO's day-ahead market, bids are due at 5 AM and the market clears by 11 AM prior to the operating day; in ISO-NE's day-ahead market, bids are due by noon and the market clears by 4 PM.

Asynchronous markets are difficult to coordinate. The problem is that NYISO's earlier-closing day-ahead market cannot directly incorporate information about the price of power available from ISO-NE, which won't be known for several hours. Similarly, after the price of power in ISO-NE is known later that day, participants cannot revise offers in NYISO's day-ahead market because that market is closed. These timing issues mean it is not possible to construct a clearing algorithm that determines an interface schedule to equate day-ahead locational marginal prices between regions.

Nevertheless, it is possible to achieve a level of coordination between day-ahead markets based on market participants' expectations about real-time prices. These expectations are incorporated into day-ahead prices by allowing participants in each day-ahead market to buy or sell at the interface proxy bus between NYISO and ISO-NE.

B. Day-Ahead External Transactions

There are two ways in which a market participant could offer to buy or sell at the interface between regions in the day-ahead market: External transactions and virtual transactions. The two are treated the same in the day-ahead market.

An external transaction offer in the day-ahead market is an offer either to buy, or to sell, that settles at the day-ahead locational marginal price at the external interface. Like today, an accepted external transaction is a binding financial arrangement between a market participant and the ISO. The external transaction does not create a physical obligation for the market participant.

With minor modifications to today's practices, both the Tie Optimization and the CTS options can accommodate external transaction offers in each ISO's day-ahead energy market. The minor modifications relate to how day-ahead external transactions are linked and settle in to the real-time market.

Linking DA and RT External Transactions

Under CTS, an external transaction that clears an ISO's day-ahead market can be linked to a specific interface bid in the same direction submitted by the same market participant. If the interface bid also clears, then the external transaction would be deemed "to flow" in real-time. That means a participant submitting an external transaction that clears in each ISO's day-ahead market, and that clears (for the same MW) as an interface bid in real-time, would have no balancing (deviation) charges associated with real-time settlement.[25]

Note, however, that interface bids can only clear in the economically-correct direction. That is a central objective of the CTS design: By only clearing interface bids in the economically correct direction, it solves one of the root causes of today's inefficiencies (see *Non-Economic Clearing* in section II.C). The point to note is that day-ahead external

[25] In NYISO, credits and debits associated with differences between a market participant's day-ahead and real-time market positions (cleared MW) are called *balancing* charges; in ISO-NE, they are commonly called *deviation* charges. We use both terms synonymously.

transaction offers need to be in the economically-correct direction to avoid balancing (deviation) charges at real-time settlement.

The same role for day-ahead external transactions can be achieved under Tie Optimization. Under that design option, a market participant submitting a day-ahead external transaction may request that the ISOs deem the transaction "to flow" in real time. Like today, a day-ahead external transaction that is deemed to flow in real time under Tie Optimization would not incur balancing (deviation) charges associated with real-time settlement. A day-ahead external transaction that is not deemed "to flow" in real time would incur a balancing (deviation) credit/debit, settled at the real-time LMP.

Under Tie Optimization, the market participant's day-ahead external transactions need to clear each ISO's day-ahead market (for the same MW) in order to avoid balancing (deviation) charges associated with real-time settlement. In addition, as with CTS, day-ahead external transactions need to clear in the economically-correct direction to be deemed to flow in real time.[26]

RATIONALE FOR PRESERVING EXTERNAL TRANSACTIONS

Why provide day-ahead external transaction functionality, in a world in which the real-time net interface schedule is optimized with either CTS or Tie Optimization? There are three main reasons.

First and foremost, external transaction offers can help improve price formation at the external interface in the (separate) day-ahead markets administered by each ISO. If there are more day-ahead offers to buy or sell at the external interface, then there is more information going into the determination of day-ahead prices, day-ahead quantities, and the market's prediction of the economically-correct power flow direction across the interface. Information on the economically-correct power flow direction for the next day, and its approximate magnitude, helps the ISOs to make day-ahead generator commitment decisions in the most cost-effective way.

Second, external transactions enable a market participant to lock-in the prices associated with buying and selling energy across the interface on a day-ahead basis. That allows the participant to avoid being exposed to the volatility of real-time price differences across the interface. Of course, those price differences should be much lower and much less volatile than they have been in the past, under either of the two solution options presented here.

[26] Under both CTS and Tie Optimization, if real-time TTC is less than the total MW of day-ahead cleared external transactions, (some) day-ahead transactions would not be deemed to flow and would incur balancing charges at real-time settlement.

Last, external transaction functionality enables a market participant with an existing contractual arrangement that obligates it to schedule an external transaction between regions to continue to satisfy that obligation. Such obligations can arise for a number of reasons outside the purview of the ISOs, such as the external scheduling requirements associated with some states' renewable energy certificate (REC) or renewable portfolio standard (RPS) programs.

C. Interface Settlement Methods

There are several methods that could be used to settle day-ahead and real-time energy schedules across the interfaces between NYISO and ISO-NE under Tie Optimization or CTS. In this section, we step through one of these possible settlement methods. Although settlements methods are (necessarily) detailed, they also convey useful information about how many of the different components of the two solution options described above work, and interact, with the day-ahead markets.

The settlement details also indicate how congestion revenue accrues across the interface is treated under CTS or Tie Optimization. That is necessary for the ISOs to be able to fund TCC/FTR products that can be used by market participants to hedge energy price risk at the interface.

The settlement method described here has several desirable properties:

- It enables (expected) congestion revenue across the interface to accrue in the day-ahead markets, even though the two ISOs' day-ahead markets continue to operate asynchronously;
- The day-ahead congestion revenue can fund a TCC/FTR that hedges day-ahead LMP differences at the interface.
- It enables the day-ahead markets to produce information about the expected real-time power transfers between regions, which can help improve each ISO's unit commitment decisions prior to the operating day.

The settlement method discussed here is applicable, with minor differences, to either the Tie Optimization option or to the CTS option for real-time scheduling. We consider the Tie Optimization case first. The extension to the CTS case involves an additional element to accommodate compensation to participants submitting real-time interface bids, explained subsequently.

Proxy Bus Prices

Under standard market design, the settlement of scheduled energy flows across an external interface is based on *external proxy bus* prices. An ISO's external proxy bus price is the bid-based incremental (dispatch) cost of delivering another megawatt to the ISO's *own* side of interface.

Note an ISO's external proxy bus price includes the cost of *internal* congestion to the interface, and the cost of energy losses to the interface. The external proxy bus LMP would be the same as the internal LMPs in the ISO's network if there is no internal congestion or losses.

In real-time, there is a *sending* (exporting) ISO and a *receiving* (importing) ISO across the interface. Figure V-1 illustrates the external proxy bus prices set by the sending and receiving ISOs when the external interface transmission capacity is binding in real-time. In this event, there is price separation between markets.

The difference in each ISO's external proxy bus prices equals the price of congestion across the interface in real-time. This is shown as the height of the shaded (green) area in Figure V-1. As discussed next, the congestion price is divided into two equal components, which serve to apportion any real-time congestion revenue equally to each ISO's congestion revenue fund.

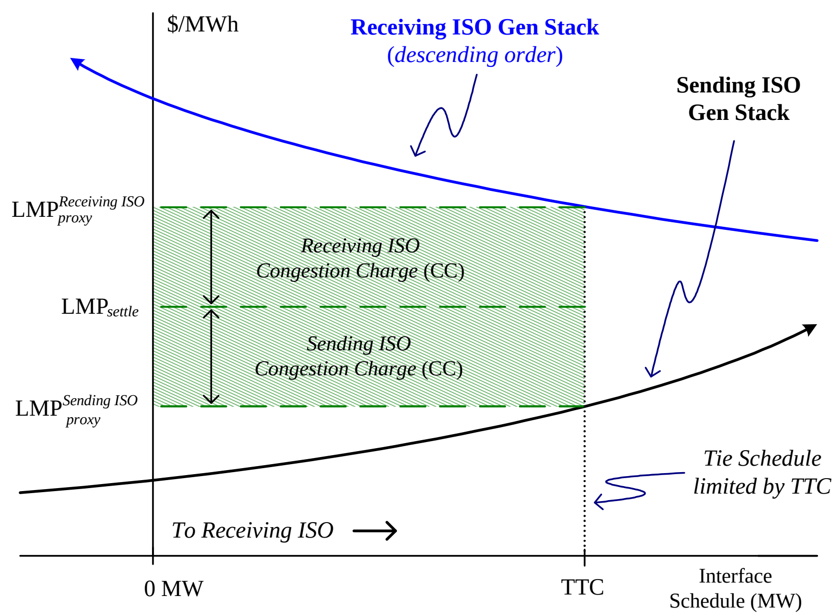

Figure V-1. Real-time external proxy bus LMPs, interface settlement LMP, and interface congestion charges (CC) under Tie Optimization.

Settlement Rules: Real-Time

Under either Tie Optimization or CTS, all load and generation pays, or is paid, the LMP at its location. For the receiving ISO, more revenue is paid by internal load than must be paid to internal generation. This difference is attributable to the imported megawatts. Under Tie Optimization, the two ISOs—acting as joint settlement administrators—must transfer funds from loads in the importing region to compensate generators in the exporting region for the imported megawatts. Under CTS, a similar transfer of funds between receiving ISO loads and sending ISO generation occurs, but through debits and credits to the market participants with accepted interface bids.

The primary complication that external interface flows pose for settlements is that when congestion occurs across an external interface, the congestion revenue must be allocated—explicitly or implicitly—between regions. While there are a number of different means to do so, one of the simplest, most transparent, and equitable methods is based on the concept of an *interface settlement LMP*.

Under Tie Optimization, the real-time interface settlement price is simply the midpoint between the sending and receiving ISOs' real-time external proxy bus prices:

Settlement LMP = ½ × (Sending ISO RT proxy bus LMP + Receiving ISO RT proxy bus LMP)

The interface settlement LMP is shown as LMP_{settle} in Figure V-1. If there is no price separation between markets, then each ISO's external proxy bus LMP will equal the settlement LMP.

The settlement and proxy bus LMPs provide for a simple method to settle the real-time energy flows across the interface, and to allocate equally any real-time congestion revenue that accrues across the external interface. Under Tie Optimization, a transfer is performed by the ISOs at the interface settlement price using an interface settlement account:

- The receiving ISO credits an interface settlement account, in an amount equal to the optimized tie schedule MW times the settlement LMP;
- The sending ISO debits the interface settlement account, in an amount equal to the optimized tie schedule MW times the settlement LMP.

The interface settlement account always nets to zero.

This method is simplest in the case where there is no price separation within or between each region. In that case, the interface settlement price equals the LMP paid by loads at its location and equals the LMP paid to generation at its location.

When there is price separation between regions, this settlement process divides the total (real-time) cost of congestion across an external interface into two equal parts. In Figure V-1, these parts are the Sending ISO Congestion Charge and the Receiving ISO

Congestion Charge. In this way, each ISO's congestion revenue fund accrues an equal amount of the total real-time congestion revenue across the external interface.

In sum, this settlement method has the following properties:

- All generation is paid the LMP at their locations, and all load pays the LMP at their locations, as usual under standard market design;
- The difference in real-time proxy prices at the external interface transparently conveys the correct real-time cost of congestion (i.e., the marginal opportunity cost of limited transmission capacity between regions);
- Any real-time congestion revenue across the external interface accrues in equal measure to the congestion revenue funds administered (separately) by each ISO.

SIMPLE EXAMPLES

Imagine day-ahead cleared load equals real-time load in each region, and there are no external transactions cleared in the day-ahead markets.   Assume no internal congestion within each ISO, and no energy losses.

Scenario A.   Suppose the RT LMP in each ISO is $50 / MWh, and Tie Optimization sets a real-time schedule of 1000 MW across an unconstrained external interface.   Generation in the sending ISO has a positive deviation from day-ahead of 1000 MW in real-time, and generation in the receiving ISO has a negative deviation from day-ahead of 1000 MW in real time. In real-time settlement, the receiving ISO debits generators with the negative deviation that hour a total of $50,000 (= $50 / MWh x 1000 MW). It transfers this amount to the sending ISO, and the sending ISO credits internal generators with the positive deviation the same amount.

Scenario B. Suppose the RT LMP is $50 / MWh in the sending ISO, $70 / MWh in the receiving ISO, and Tie Optimization sets a real-time schedule of 1200 MW that congests the external interface.   Generation in the sending ISO has a positive deviation from day-ahead of 1200 MW, and generation in the receiving ISO has a negative deviation from day-ahead of 1200 MW. In real-time settlements:

- The receiving ISO debits internal generation at its LMP of $70 / MWh, in an amount of $84,000 (= $70 / MWh x 1200 MW);
- The interface settlement price is $60 / MWh, so the receiving ISO transfers $72,000 (=$60 / MWh x 1200MW) to the sending ISO;
- The sending ISO credits internal generation at its LMP of $50 / MWh, in an amount of $60,000 (= $50 / MWh x 1200 MW);

- Each ISO accrues a credit to its congestion revenue fund of $12,000, equal to each ISO's interface congestion charge of $10 / MWh times the 1200 MW interface schedule.

The important points to note about this example are two. First, market participants with real-time balancing charges (deviations) from day-ahead positions are credited or debited at the LMP at their location, as usual under standard market design.

Second, regardless of the magnitude of the price separation between regions, each ISO has the same real-time congestion price across the external interface. If the numbers assumed in Scenario B were instead applied between two locations separated by a congested interface *within* a single ISO, the congestion price across the internal interface would be $20 / MWh. When it applies across an *external* interface, each ISO applies an interface congestion price of half as much. By doing so, the total congestion price applied by the two ISOs—here $20 / MWh—is the economically-correct congestion price under standard market design.

CTS Interface Settlement Prices

The principles underlying the settlement method outlined above apply to both Tie Optimization and CTS. However, there are some important differences. These differences are necessary to accommodate settlement of the interface bids under CTS.

Under CTS, there are *two* real-time interface settlement prices. Each ISO's interface settlement price is equal the ISO's external proxy bus price adjusted for the cost of congestion across the interface:

- Receiving ISO's settlement LMP = Receiving ISO's RT proxy bus LMP – Scheduled Congestion Charge
- Sending ISO's settlement LMP = Sending ISO's RT proxy bus LMP + Scheduled Congestion Charge

To interpret the settlement LMPs and Scheduled Congestion Charges, a graph may help. Figure V-2 (*next page*) shows how the cleared interface bids affect real-time settlement under CTS. As before, the external proxy bus prices represent each ISO's bid-based incremental (dispatch) cost of delivering another megawatt to the ISO's *own* side of interface.

The supply curve in the lower axes in Figure V-2 is the interface bid stack (only interface bids in the economically correct direction are shown). When the external interface is congested in real time, the last accepted interface bid is the marginal interface bid (MIB). In the upper axes, the marginal interface bid is the height of the (unshaded) box between the sending and receiving ISO settlement prices. Each scheduled congestion charge (SCC) per MW is the height of the green box between the ISO's proxy bus LMP and its settlement LMP.

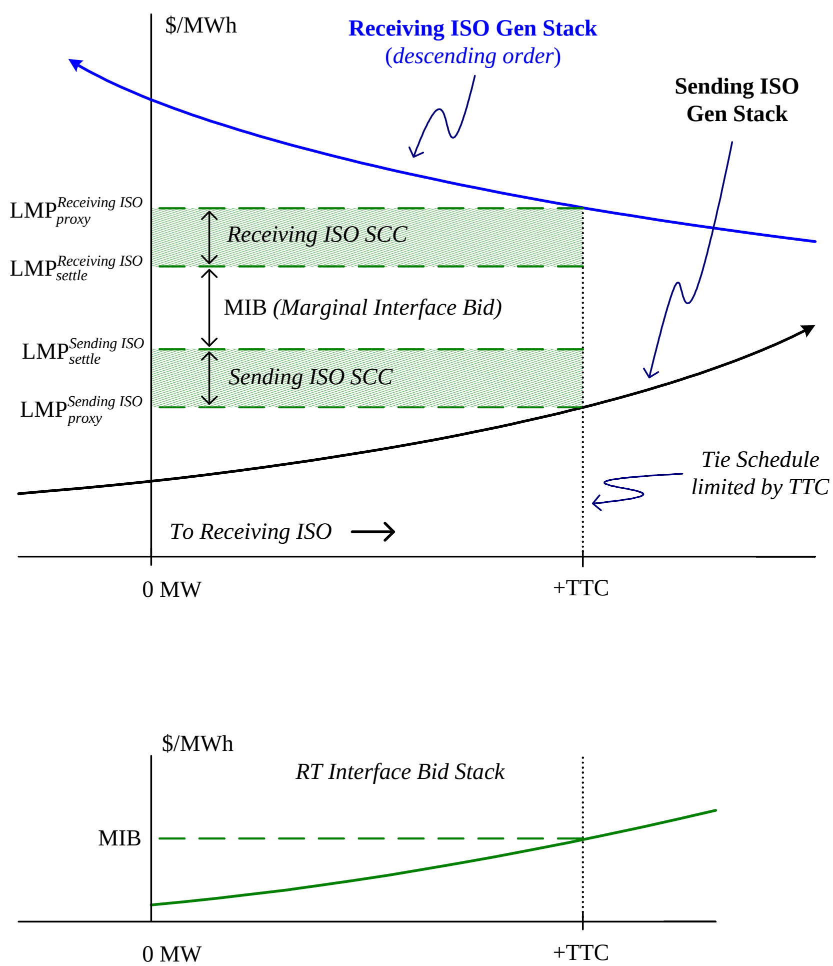

Figure V-2. Scheduled congestion charges (SCC) and marginal interface bid (MIB) under CTS when the interface is congested in real-time.

These settlement and proxy bus LMPs provide for a method to settle the real-time energy flows across the interface, and to allocate any (real-time) congestion revenue between markets. The real-time settlement rules for interface bids are two:

- The receiving ISO credits participants submitting cleared interface bids, in an amount equal to the cleared interface bid MW times the receiving ISO settlement LMP;
- The sending ISO debits participants submitting cleared interface bids, in an amount equal to the cleared interface bid MW times the sending ISO settlement LMP.

All participants with cleared interface bids are charged a uniform price by the receiving ISO, and receive a uniform price from the sending ISO. That means the net gain to a participant with a cleared interface bid is the MIB price times the quantity (in MW) of cleared interface bids it submitted.

Note, however, that if a participant with a cleared interface bid also has a cleared day-ahead external transaction for the same MW, then the two transactions will offset in real-time settlement. The interface bid settlement rules generate net cash flows in real-time settlements only for the *deviation* (imbalance) in cleared quantities between the interface bid and the day-ahead transaction.[27]

CTS Scheduled Congestion Charges

Figure V-2 shows a situation where there is congestion in real-time. There is one aspect of the SCC that applies to the CTS option and is not readily conveyed by Figure V-2.

While the external proxy bus prices are real-time LMPs, the SCC is determined when the tie is *scheduled.* Under HFS, the interface is scheduled before the real-time prices are known. The *expected* real-time external proxy bus LMPs at the time the tie is scheduled are called as the ISOs' *scheduling prices.* Under CTS, the SSC is calculated by subtracting the marginal interface bid (MIB) from the difference in scheduling prices:

SSC = (Receiving ISO's scheduling price – Sending ISO's scheduling price) – MIB

If there are no changes in system conditions between when the tie is scheduled and when real-time internal LMPs are determined, then the scheduling price and the RT proxy bus LMP will be the same.

[27] This is achieved by crediting (or debiting) the external transaction at the real-time proxy price. That is a net zero settlement if the interface bid and day-ahead external transaction have an identical cleared MW, and non-zero for MW deviations.

Why set the congestion charge, and thus the sending ISO's proxy price, based on *scheduling* prices? The reason is that it affects who bears latency risk. Even under HFS, there exists a (15 minute) latency delay between when the tie schedule is set and when the power actually flows. If, for instance, the sending ISO experiences a contingency that raises its real-time internal LMP above the price expected when the tie is scheduled, the sending ISO debits the interface bidder the sending ISO's actual real-time external proxy bus LMP less a fixed SCC charge, times the cleared interface bid MW. In this way, interface bidders (that do not have a matching day-ahead position) bear some of the financial risk associated with latency delays under HFS.

Real-time Settlement of Day-Ahead External Transactions

The interface settlement rules for Tie Optimization and for CTS generalize to handle real-time settlement of external and virtual transactions at external proxy buses. The key point is that for any day-ahead external or virtual transaction at the external proxy bus that incurs real-time balancing (deviation) charges, the real-time settlements are priced at the external proxy bus LMP plus (or minus) the interface congestion charge. That is, external transactions are priced at the interface settlement LMP.

Although numerical examples become detailed, the settlement rules are conceptually straightforward. Under both Tie Optimization and CTS:

- A cleared day-ahead virtual transaction at an external proxy bus is settled in real-time at the ISO's interface settlement LMP.

Under Tie Optimization:

- A cleared day-ahead external transaction that is not deemed to flow in real time is settled in real-time at the interface settlement LMP;
- A cleared day-ahead external transaction that is deemed to flow in real time has no balancing (deviation) charges associated with real-time settlement.

Under CTS, the rules are similar but a day-ahead external transaction requires a corresponding cleared interface bid in order to avoid balancing (deviation) charges in real-time settlement:

- A cleared day-ahead external transaction that does not have a matching cleared interface bid for the same MW is settled in real-time at the ISO's interface settlement LMP;
- A cleared day-ahead external transaction that has a matching cleared interface bid for the same MW has no balancing (deviation) charges associated with real-time settlement.

Settlement Rules: Day-Ahead

The settlement rules for external and virtual transactions in the day-ahead market at the proxy bus follow standard market design. These rules operate in the same way under CTS and Tie Optimization. Since the day-ahead markets operate asynchronously, day-ahead settlement, day-ahead external proxy bus pricing, and day-ahead external interface congestion charges are applied by each ISO separately.

The main day-ahead settlement rules for external (and virtual) transactions at an external proxy bus pricing point are these:

- A day-ahead external transaction or virtual transaction offer to buy (export) at the proxy bus clears if the offer price exceeds the day-ahead proxy bus price; and

- A day-ahead external transaction or virtual transaction offer to sell (import) at the proxy bus clears if the offer price is less than the day-ahead proxy bus price.

- The proxy bus price equates the total MW of supply and demand that clear at the proxy bus (unless that level of MW exceeds total transmission capability).[28]

Real-time charges and credits are based only on deviations from day-ahead positions. In this way, a market participant submitting a day-ahead external transaction can (largely) avoid exposure to real-time prices across the interface.

Economic Implications

The basic settlement method outlined above has a number of important economic implications.

First, it enables congestion revenue associated with real-time interface transmission constraints to accrue in the day-ahead market, to the extent that day-ahead prices anticipate it. That enables a traditional FTR/TCC instrument to be funded from day-ahead congestion revenue.

Second, the method is applicable to both the CTS option and the Tie Optimization option (which amounts to treating the interface bids as priced at zero). Thus, to some degree, the decision over whether the ISO's should pursue the CTS option or the Tie Optimization option for the process to determine the real-time net tie schedule can be divorced from the decision over how to set proxy-bus prices and settle the associated cash flows.

[28] If total transmission capacity binds day-ahead, then the proxy bus price must be modified by the shadow cost of the transmission constraint. We omit the mathematical details.

Third, the settlement logic reveals that CTS and Tie Optimization differ in the extent to which they enable a TCC/FTR holder to hedge the total (internal) LMP difference between regions. To see why, compare the total congestion surplus (the shaded green areas) in Figures V-1 and V-2: The congestion surplus is larger with Tie Optimization. It is equal to the interface schedule megawatts times the *sum* of the SCCs + MIB shown in Figure V-2. In effect, the profit margin of a participant with a cleared interface bid (the value of MIB) reduces the congestion revenue that would otherwise ultimately accrue to congestion revenue rights holders under Tie Optimization.

VI. Hedging Price Risk at the Interface

A subset of market participants actively trade power between regions, or have long-term contracts tied to assets in both New York and New England. For these participants, the existing external transaction system provides limited means to hedge against the risk of price differences between regions. As Figure II-7 indicates, real-time price differences across the interface are historically volatile.

Although Tie Optimization and CTS are both designed to reduce price differences between regions, and should therefore reduce this volatility substantially, congestion cannot be whisked away by market design. A hedging mechanism, such as TCC/FTRs, at the interface may be valuable to market participants.

Example

Suppose a market participant with a generator located in New York has a year-long supply arrangement with a municipal distribution utility in New England. Under this arrangement the municipal utility pays the market participant a fixed price per MWh, in exchange for which the participant remits to ISO-NE the day-ahead energy market charges that the municipal utility incurs at its location. (This type of financial arrangement is common, often implemented as an internal bilateral transaction administered by ISO-NE's settlement department).

Under this arrangement, the market participant is subject to four distinct price risks: Energy price risk at the generator; internal congestion in NYISO between the generator's location and the NE/NY border; internal congestion in ISO-NE between the municipal utility's location and the NE/NY border; and price risk across the interface itself.

Existing TCC/FTR instruments enable the market participant to (largely) hedge against the internal congestion price risk within each ISO. However, there is no ready means to hedge the price risk between regions. If the LMP in New England rises relative to the LMP in New York, the market participant ends up with a high bill from ISO-NE for the municipal utility's load obligation, and low revenue at the generator's location in New York with which to cover it.

IMPLICATIONS

The high (historical) volatility of the price difference across the interface suggests a market participant in this position faces a significant financial exposure on its fixed-price contract with the municipal utility. The inability to hedge a significant price risk will inhibit a participant's willingness to enter into a fixed price contract in the first place—or increase the fixed price the participant is willing to offer in a long-term contract. That reduces the competitiveness of markets for long-term, fixed-price power contracts.

In effect, even if this (hypothetical) municipal utility never deals with the world of TCCs/FTRs directly, or conducts any inter-regional energy trading *per se*, the opportunities it can find to acquire stable-price long-term power supplies in today's market environment are affected by whether hedging instruments across ISOs' external interfaces are well designed.

DESIGN ISSUES

The natural instrument with which to enable market participants to manage price risk across the interface is a TCC/FTR product. Accordingly, both of the real-time interface scheduling options in this report provide a means to fund this financial product.

Economic coordination of real-time power flows enables the two ISOs to set congestion prices at their external (proxy-bus) pricing points in real-time. A settlement system such as that outlined in section V.C will accrue the congestion revenue, on a day-ahead basis, during settlements. This day-ahead congestion revenue can be paid out to the buyer of the TCC/FTR, partially reducing its price risk across the interface.

While the market design for a TCC/FTR at the interface is mostly standard (in the sense of mirroring how a nodal TCC/FTR works between points internal to an ISO's network), there are a few additional wrinkles. These arise because each ISO separately administers the TCC/FTRs between its internal locations and the external interface.

TWO TCC/FTRS

The settlement system described above (section V.C) has the property that both ISOs accrue congestion revenue across the interface. This provides for an appealing means to structure a TCC/FTR to pay out this congestion revenue: Each ISO issues a *separate* TCC/FTR to the external interface. The TCC/FTR pays the difference between the (day-ahead) price at an internal location and the ISO's (day-ahead) interface settlement price. An ISO's day-ahead interface settlement price is the ISO's day-ahead price at the external proxy bus plus (or minus) the ISO's day-ahead interface congestion price.

If day-ahead market prices are perfect predictors of real-time prices, then the day-ahead congestion revenue of a TCC/FTR to the external interface will equal the ISO's congestion charge as shown in Figure V-1 (under Tie Optimization) or schedule congestion charge as shown in Figure V-2 (under CTS), plus any internal congestion charge to the external proxy bus. In effect, if day-ahead prices match real-time prices, then the TCC/FTR to the external interface pays its bearer the sum of any congestion cost *to* the external proxy bus *plus* one-half the total cost of congestion *across* the external interface.

There are some advantages and disadvantages to structuring TCC/FTRs at the external interface as separate products administered by each ISO. From the perspective of a market participant that may wish to acquire the product, it provides flexibility for a

TCC/FTR buyer to manage congestion price risk in each market separately, consistent with the individual day-ahead market executions. However, a TCC/FTR buyer that wishes to acquire insurance against price separation between a location within New York and a location within New England will need to acquire two TCC/FTRs, and participate in the TCC/FTR auctions administered by two ISOs. With this structure, each ISO's TCC/FTR to the external interface remits the day-ahead congestion revenue collected by the ISO's own day-ahead market to parties that acquired its TCC/FTR across the interface.

From an administrative standpoint, there are a number of advantages. As with any TCC/FTR, the ISOs need to cover financial assurance for the instrument, estimate revenue insufficiency risk (that is, how many megawatts of TCCs/FTRs to auction), and decide how far in advance to issue the TCCs/FTRs. Both NYISO and ISO-NE have well established, and somewhat different, administrative procedures and tariff provisions to carry out these functions. Structuring TCC/FTRs as separate products to the external interface will enable each ISO to continue to use its existing process for these essential functions.

REVENUE ALLOCATION

From the perspective of the revenue-rights holders in each region, this separate administration of TCC/FTR products "to the interface" addresses an important issue: How the total revenue from the sale of TCCs/FTRs at the interface accrues to two different ISOs' auction revenue rights holders. Under the two-TCC/FTR structure, each ISO would credit the auction-revenue rights holders in its region alone for the proceeds from the interface TCC/FTR auction instrument it administers. The allocation of auction revenue from TCC/FTR instruments to the external interface would follow each ISO's existing tariff provisions for the allocation of TCC/FTR auction revenue.

CONGESTION RESIDUALS

The third issue to consider is the allocation of real-time congestion residuals (in New England, congestion residuals are often simply called *real-time congestion*). Real-time congestion residuals can arise in two ways. One way occurs if (a) the day-ahead markets do not predict congestion (the day-ahead cleared quantity at an ISO's external proxy bus is less than total transmission capacity across the interface), but (b) in the real-time market total cleared quantities are greater, and the interface transmission constraint binds in real-time. In this case, there is a positive contribution to total congestion revenue from participants' real-time deviations from day-ahead quantities.

Alternatively, congestion residuals can occur when transmission constraints bind in real-time operations at a lower MW rating than the transmission capacity value used to clear the day-ahead market. In this situation, the real-time congestion residual is typically negative.

Both NYISO and ISO-NE have established procedures and tariff language governing the allocation of real-time congestion residuals.[29] The only new element here is how to split it between each ISO's market participants when it accrues across the interface, instead of across internal transmission constraints. The settlement method outlined in section V.C addresses this issue in a direct and equitable way. Because each ISO's real-time interface settlement LMP is calculated to always produce equal real-time interface congestion charges by the sending and receiving ISO, any real-time congestion revenue (whether positive or negative) will always be accrue in equal measure to each ISO's congestion revenue fund.

Back to CTS and Tie Optimization

It is important to observe that the foregoing TCC/FTR design issues are equally germane to both the CTS option and the Tie Optimization option. Thus, to a significant degree, the decision of whether the ISOs should pursue the CTS option or the Tie Optimization option to schedule real-time net tie flows is distinct from decisions on TCC/FTR auction revenue and instrument design.

A final, more subtle, economic issue should be pointed out in connection with hedging price risk across the interface. This is the fact that price differences between New York and New England are primarily not due to congestion. As shown in Figure II-1, congestion occurs only a few percent of the hours per year (at the NYN interface). Yet the price differences across this interface, as shown in Figure II-6, are non-zero nearly *every hour of the year*. The risk that market participants may wish to hedge between regions is not primarily caused by congestion.

Nevertheless, the two solution options presented here would enable a TCC/FTR, constructed in a standard way, to provide a hedge against price risk for day-ahead price separation at the interface. In addition, a settlement system like that outlined above (section V.C) would enable a market participant to transact on a day-ahead basis at each ISO's external proxy bus, then avoid (most causes of) real-time balancing (deviation) charges under either Tie Optimization or under CTS. For these reasons, the combination of a TCC/FTR instrument across the interface and either Tie Optimization or CTS for real-time net tie scheduling would help market participants to hedge price risk across the interface in a way they cannot do so today.

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[29] Neither of the real-time net tie scheduling solution options presented in this paper contemplate changes to these procedures.

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