March 2, 2022

BY ELECTRONIC FILING

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

Re: **Revisions to Market Rule 1 and Related Tariff Provisions to Accelerate Billing of Certain Forward Capacity Market Payments and Charges, Docket No. ER22-_____-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"), joined by the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties"),[3] hereby submits to the Federal Energy Regulatory Commission (the "Commission") this transmittal letter and revisions to the ISO's Transmission, Markets and Services Tariff (the "Tariff") to (1) accelerate the settlement and billing of certain Forward Capacity Market ("FCM") charges and payments from a monthly settlement and billing to a daily settlement and bi-weekly billing (the "FCM Acceleration Changes"); (2) make several corrections and clarifications to the FCM Cost Allocation provisions previously approved by the Commission in 2018,[4] before those go into effect on June 1, 2022 (the "FCM Cost Allocation Changes"); (3) revise the method to submit Requested Billing Adjustments (the "RBA Changes"); and (4) make several conforming and clean-up changes (the "Clean-up Changes").

The FCM Acceleration Changes are supported by the testimony of Mark Wing (the "Wing Testimony," sponsored solely by the ISO),[5] and the joint testimony of Kelly Reyngold and Kevin

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[1] 16 U.S.C. § 824d.

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff. Section III of the Tariff is known as Market Rule 1.

[3] Under New England's Regional Transmission Organization arrangements, the rights to make this filing of changes to the Tariff under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO matters, supported the changes reflected in this filing and, accordingly, joins in this Section 205 filing.

[4] *See ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER18-2125-000 (issued Sept. 26, 2018) (FERC delegated letter order).

[5] Mr. Wing is a Supervisor in the ISO's Market Analysis & Settlements Department.

Coopey ("Reyngold/Coopey Testimony," also sponsored solely by the ISO).[6] The Wing Testimony also supports the FCM Cost Allocation Changes and the Reyngold/Coopey Testimony also supports the RBA Changes. The FCM Acceleration Changes are discussed in Section III.A and B herein, the FCM Cost Allocation Changes are discussed in Section III.C, the RBA Changes are discussed in Section III.D, and the Clean-up Changes are discussed in Section III.E.

As explained in Section IV of this filing letter, the complete set of revisions were unanimously supported by NEPOOL. As addressed in Section V of this transmittal letter, the ISO respectfully requests an effective date of May 1, 2022 for the RBA Changes. For the balance of revisions proposed in this filing, the ISO requests an effective date of June 1, 2022. The ISO requests that the Commission issue an order accepting these Tariff revisions no later than 60 days from the date of this filing.

I. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the Regional Transmission Organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement ("TOA") 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 and the North American Electric Reliability Corporation.

The signatories to the New England Power Pool Agreement, which was first entered into in 1971, are referred to collectively as "NEPOOL." Currently, there are more than 510 signatories, which are referred to either as "Participants" or "members." Participants include all of the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers (including owners of distributed generation and aggregators of such generation), developers, end users, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[7] the Participants act through the NEPOOL Participants Committee. Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement authorize the Participants Committee to represent NEPOOL in proceedings before the Commission. Through the Commission-approved Participant Processes, NEPOOL is the vehicle through which all stakeholders with business interests in New England are able to provide informed input and advice to ISO-NE.

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

[6] Ms. Reyngold is the ISO's Controller. Mr. Coopey is a Supervisor in the ISO's Finance and Market Risk Department.

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

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II. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[9] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[10] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[11] 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

[8] 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.

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

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

[11] *Id.* at 9.

alternative rate designs."[12] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[13] 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.[14]

III. EXPLANATION OF THE TARIFF REVISIONS

The ISO settles transactions related to the various wholesale electricity markets, market products, and other services that it administers in New England. Accordingly, the ISO issues customer bills detailing all applicable charges and payments. As specified in the ISO New England Billing Policy,[15] charges and payments are either billed (or credited) twice weekly or monthly. Charges and payments that are billed twice-weekly are "Hourly Charges" and include charges and payments related to the real-time and day-ahead energy markets.[16] Charges and payments billed monthly include charges and payments related to the FCM and certain transmission charges.[17]

To purchase enough capacity to satisfy the region's future electricity needs and allow enough time to construct new capacity resources, the ISO administers annual Forward Capacity Auctions ("FCAs") approximately three years in advance of the year-long Capacity Commitment Period ("CCP"). Through the FCA, resources are awarded a Capacity Supply Obligation ("CSO"). For each Obligation Month in the CCP, Market Participants receive payments based on each of their resources' CSO. After each FCA, Market Participants have several opportunities to acquire, increase, or shed all or part of their CSO for a given capacity commitment period through annual reconfiguration auctions, monthly reconfiguration auctions, and monthly Capacity Supply Obligation Bilaterals.

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

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

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

15 The ISO New England Billing Policy is Exhibit ID to Section I of the Tariff ("Billing Policy").

16 Hourly Charges include each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy, as well as for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, and Net Commitment Period Compensation. *See* Billing Policy, Section 1.3.

17 The majority of the other charges are defined as Non-Hourly Charges, which are calculated and settled on a monthly basis. Non-Hourly Charges include charges relating to the Forward Capacity Market and certain ancillary services, Participant Expenses, charges under Section IV of the Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the Open Access Transmission Tariff (other than charges arising under Schedules 1, 8, and 9 thereto, which are separately billed as Transmission Charges). *See* Billing Policy, Section 1.3.

For each obligation month in the CCP, resources with a CSO supply the capacity for the relevant CCP in exchange for a market-priced capacity payment. Resource payments and charges are allocated to load-serving entities based upon their Capacity Load Obligation ("CLO") and their share of historic contributions to peak load, adjusted to reflect bilateral transactions and certain other specific allocations, and the performance charges and payments are settled between supply resources. These payments and charges are billed in accordance with the Billing Policy. Associated financial assurance requirements similarly ensure that Market Participants have sufficient collateral on hand to cover their FCM charges for that Obligation Month. The FCM Financial Assurance Requirements are prescribed in the ISO New England Financial Assurance Policy.[18]

At the May 10, 2019 NEPOOL Budget and Finance Subcommittee meeting, a Market Participant asked the ISO to assess whether the FCM settlement and billing cycle could be accelerated. The ISO formed a working group to perform the assessment, which ultimately recommended that the acceleration proposal was feasible and should move forward. As a result of the FCM Acceleration Changes discussed in detail below, FCM payments and charges will settle more frequently, accelerating payments to capacity resources and reducing existing financial assurance requirements for Market Participants.

A. Modifications to Accelerate the Settlement and Billing of Certain FCM Payments and Charges

Currently, the ISO settles FCM charges and payments on a monthly basis, and, as noted above, these are included on a participant's monthly invoice or remittance. As explained in the Wing Testimony, the ISO proposes to settle most of the FCM payments and charges on a daily basis and therefore, include those FCM charges and payments on the twice-weekly bills. Under the FCM Acceleration Changes, the FCM payments that will be settled on a daily basis are associated with CSO transactions from the following activities: FCAs (including the substitution auction), annual and monthly reconfiguration auctions,[19] and monthly CSO Bilaterals.[20] Charges for those transactions will also be allocated daily, along with charges for the following FCM-related items:

- HQ Interconnection Capability Credits,
- Self-supply adjustments,
- Intermittent Power Resource Capacity adjustments,
- Multi-year rate election adjustments,
- CTR transmission upgrade charges, and

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[18] The ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Tariff ("Financial Assurance Policy").

[19] Annual Reconfiguration Transactions will be settled daily. *See* Revised Tariff Section III.13.5.4.3.

[20] *See* Revised Tariff Section III.13.7.1.1 (specifying that each charge identified in Section III.13.7.1.1 (a) through (d) will be divided by the number of days in the month to derive a daily settlement value).

- CTR Pool-Planned Unit charges.[21]

Revisions have been made to each relevant section of Market Rule 1 to reflect the acceleration of these components. Daily values for these payments and charges must be derived to include in the daily settlement.[22] The ISO will also calculate a daily Market Participant Zonal Capacity Obligation value to allocate the charges.[23] In addition, the changes include a revised submittal deadline for Capacity Load Obligation Bilaterals in order to accommodate the new settlement timeline[24] and remove Tariff language referring to the FCM settlement as a monthly process.[25] The Tariff changes being submitted in this filing specify how daily payments will now be calculated.[26]

A small number of FCM settlement payments and charges will continue to be billed on a monthly basis. These include settlements related to the following: forfeited Financial Assurance,[27] resources retained for reliability,[28] failure to cover charges,[29] certain export capacity transactions,[30] Capacity Performance Payments,[31] and excess revenues.[32] Settlements for these charges generally occur infrequently, or data required for the settlement is not available until after the end of the Obligation Month.[33] Accordingly, the tariff provisions regarding such payments and charges will not be modified and will remain monthly.

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[21] *See* Revised Tariff Section III.13.7.5.1.1 (explaining that each charge described in Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value).

[22] *See* Revised Tariff Section III.13.7.1.1 (calculating a daily value for Charges Reflecting CSOs), Revised Tariff Section 13.7.5.2 (calculating a daily CLO for each Market Participant and Capacity Zone using daily Coincident Peak Contributions), Revised Tariff Section III.13.7.5.4.4(f) (calculating a daily value for Specifically Allocated CTRs Associated with Transmission Upgrades), and Revised Tariff Section III.13.7.5.4.5(b) (calculating a daily value for Specifically Allocated CTRs for Pool-Planned Units).

[23] *See* Wing Testimony at 8.

[24] *See, e.g.*, Revised Tariff Section III.13.5.2.1.1, (requiring that Capacity Load Obligation Bilaterals be submitted to the ISO by the first Business Day of the month in order to be included in the initial settlement).

[25] *See* Revised Tariff Section III.13.1.4.3.1 (which specifies that the monthly Measurement and Verification Summary Reports provided for On-Peak Demand Resources and Seasonal Peak Demand Resources shall be the basis for settlement, which is no longer specified on a monthly basis).

[26] *See, e.g.*, Revised Tariff Section III.13.7.3 (specifying that a resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's *daily* Capacity Base Payments for the Obligation Month). (emphasis added)

[27] Tariff Section III.13.1.9.2.3.

[28] Tariff Section III.13.1.2.3.1.5.1(d).

[29] Tariff Sections III.13.3.4(b) and III.13.7.5.1.1.10.

[30] Tariff Section III.13.7.1.3.

[31] Tariff Section III.13.7.2.

[32] Tariff Section III.13.7.5.3(b).

[33] *See* Wing Testimony at 8.

The FCM settlement payments and charges that will be settled on a daily basis are captured in the Billing Policy with a new defined term: "Daily FCM Charges."[34] The Daily FCM Charges will be included as part of the Hourly Charges and as such will follow the same billing schedule for all other Hourly Charges, which as noted above is twice-weekly. Under the proposal, charges that will continue to settle on a monthly basis are defined as "Monthly Forward Capacity Market Charges and Payments."[35]

B. Revisions to Financial Assurance Policy

The revisions to accelerate the billing of the FCM payments and charges described above will result in changes to related FCM Financial Assurance Requirements found in the Financial Assurance Policy. Because certain FCM payments and charges will settle more frequently, the proposed changes accelerate payments to resources providing capacity, while reducing the outstanding FCM charges to Market Participants who pay for capacity. As a result, the FCM Financial Assurance Requirements for capacity resources can be reduced.

Market Participant FCM Financial Assurance Requirements are determined pursuant to Section VII of the Financial Assurance Policy, which calculates FCM Financial Assurance Requirements for CLO and CSO separately. As described in Section VII.A of the Financial Assurance Policy, the payment due to the participant as a result of a CSO for the prior month serves as a credit against financial assurance obligations incurred from participating in the market until the monthly bill issued, while FCM charges from Market Participants with CLO are collateralized through FCM Capacity Charge Requirements as described in Section VII.C of the Financial Assurance Policy.[36]

The amount of financial assurance that a Market Participant is required to provide is in large part a function of the length of time between incurring a FCM obligation and the time when those obligations are billed and ultimately collected. Because, under the proposal, FCM charges and payments will be settled on a daily basis, the proposed changes reduce the amount of financial assurance that must be held on the FCM obligations that are subject to twice-weekly billing.

To effectuate these changes, the ISO will add a new component, Daily FCM Requirements, to the existing FCM Financial Assurance Requirements. As discussed in the Reyngold/Coopey Testimony, a Market Participant's Daily FCM Requirements will comprise three components: unpaid daily FCM charges, unbilled daily FCM charges, and the Daily FCM Obligation Estimator.[37] The third component of this calculation incorporates a number of inputs, including

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[34] *See* Revised Billing Policy Section 1.3 (defining Daily FCM Charges as "daily Forward Capacity Market charges and payments").

[35] *See* Reyngold/Coopey Testimony at 8 (citing Revised Billing Policy Section 2.4e, defining Monthly Forward Capacity Market Charges and Payments as "the Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of capacity charges, penalties Capacity Performance Payments and other transactions in the Forward Capacity Market that are not included in the Daily FCM Charges").

[36] *Id.* at 4.

[37] *Id.* at 8-9.

FCM daily payments for prior and current months, the latest settled FCM daily charges for each participant, as well as an FCA price ratio that produces a weighted average commitment period price for the unsettled period in the event that period spans two Capacity Commitment Periods.[38] By incorporating FCM daily credits for both the prior and current month, the methodology yields a better estimate of obligations, because these obligations can fluctuate over different monthly periods.

While these changes decrease the amount of financial assurance required for FCM obligations, it is important to underscore that they do not increase any risk to the market.[39] Instead, as the Reyngold/Coopey Testimony explains, "by accelerating the settlement and billing of the FCM, a Market Participant's obligations come due more frequently, rather than allowing those obligations to accrue or build up over an extended period of time (*i.e.*, the entire month) before payment is due. . . . More frequent settlement and billing alleviates the existing large build-up of obligations for charges that have been incurred (currently between 30-45 days worth) resulting in a much smaller amount of unpaid charges (7-16 days' worth) that are at risk of a potential default."[40]

As the current monthly FCM Capacity Charge Requirements will be replaced with the new Daily FCM Requirements, Financial Assurance Policy Section VII.B.3.C has been removed and reserved for future use.[41] Furthermore, Section VII.F.1(a) of the Financial Assurance Policy has been amended to clarify that, in the event a participant seeks to transfer its CSO in a reconfiguration auction, the current month FCM charges are prorated to the proportion of remaining days in the month.[42]

C. Revisions to FCM Cost Allocation Process

As discussed in the Wing Testimony, the ISO proposes five discrete changes to certain portions of the Tariff approved by the Commission in 2018 as part of the FCM Cost Allocation Improvements Project.[43] Those revisions had two purposes. First, they revised the Tariff cost allocation methodology to align with the use of sloped demand curves. Second, the revisions increased transparency by eliminating the use of a zonal blended rate for cost allocation purposes, replacing the blended rate with a provision that separately calculates and allocates each of the discrete charges and adjustments reflected in the blended rate.[44]

[38] *See* Revised Financial Assurance Policy Section III.A(ii).

[39] *See* Reyngold/Coopey Testimony at 7-8.

[40] *See* Reyngold/Coopey Testimony at 5-6.

[41] *See* Reyngold/Coopey Testimony at 12.

[42] *See* Revised Financial Assurance Policy Section VII.F.1(a).

[43] *See ISO New England Inc.*, Docket No. ER18-2125-000 (issued Sept. 26, 2018) (FERC delegated letter order).

[44] *See ISO New England Inc. and New England Power Pool Participants Committee*, Filing re FCM Cost Allocation Improvements, Docket No. ER18-2125-000 (filed August 1, 2018).

The ISO has been working to implement these changes, which will go into effect on June 1, 2022, and has discovered that several Tariff provisions[45] would benefit from additional refinement and clarity, including:

- a revision to the formula to calculate the charge rate for the Intermittent Power Resource capacity adjustment. In one place, the calculation uses an existing term ("*total Capacity Load Obligation* in all Capacity Zones") that is incorrect, and the ISO is revising this to use "*total Zonal Capacity Obligation* in all Capacity Zones" (emphasis added) to accurately capture the correct term;[46]
- clarification that the Capacity Transfer Right Pool-Planned Unit Charge is allocated on a system-wide basis as opposed to a zonal basis. The current Tariff language is not clear that the allocation is system-wide rather than zonal, and the ISO proposes to correct this by explicitly stating the allocation is to total CLO;[47]
- a revision to the failure to cover adjustment. This adjustment is allocated to Market Participant CLO – a monthly value. However, the same section indicates that Zonal Capacity Obligation – a daily value that is unlikely to equal the monthly CLO – is used to calculate the rate. The ISO is revising the Tariff to use total CLO as the denominator in this rate calculation, to correctly reflect the monthly CLO value;[48]
- a clarification in one provision that the defined term "Coincident Peak Contribution" should be used instead of existing lower case language;[49] and
- a revision to the specifically allocated CTRs for Pool-Planned Units calculation to clarify that these payments reflect seasonal claimed capability values at the time of qualification,[50] as CSO values are based upon recent seasonal claimed capability values at the time of qualification.[51]

D. Revisions to Requested Billing Adjustment Process

The ISO is also proposing revisions unrelated to the FCM Acceleration and FCM Cost Allocation Changes as part of this filing. The Billing Policy contains a procedure for Market Participants to dispute invoices and remittances through Requested Billing Adjustments.[52] The current Billing Policy requires Market Participants to submit Requested Billing Adjustments ("RBAs") in writing to the ISO's Chief Financial Officer.[53] Importantly, the Billing Policy does

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[45] The clarifications are found in Revised Tariff Sections III.13.7.5.1.1.6, III.13.7.5.1.1.9, III.13.7.5.1.1.10, and III.13.7.5.4.5.

[46] *See* Revised Section III.13.7.5.1.1.6.

[47] *See* Revised Section III.13.7.5.1.1.9.

[48] *See* Revised Section III.13.7.5.1.1.10.

[49] *See* Revised Section III.13.7.5.2.

[50] *See* Revised Section III.13.7.5.4.5.

[51] *See* Tariff Section III.13.1.2.2.1.

[52] *See* Billing Policy Section 6.

[53] *See* Billing Policy Section 6.3.1.

not prescribe the method of delivery for RBAs, and as a result the ISO currently receives them through email.[54]

Because of the various controls for email (e.g., spam filters), it is possible that a RBA may not be properly received and documented. As a result, the RBA Changes will require Market Participants to submit RBAs to ISO Participant Support and Solutions via its established and centralized online support system (AskISO).[55] Additionally, the RBA Changes provide that the RBA will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the disputing party.[56] The ISO's centralized support system automatically generates a case number for each new inquiry received. The ISO has also proposed a conforming change in Revised Tariff Section III.3.8 to reflect the RBA notice adjustment. The proposed changes will allow for consistency and structure around submittal, provide acknowledgement of receipt, and reduce cybersecurity risk.[57]

E. Conforming and Clean-Up Changes

As part of this filing, the ISO is also making several cleanup and conforming revisions to the Tariff. These include:

- three ministerial revisions to use placeholders instead of designated staff in the Appendix I Form Cost-of-Service Agreement;[58]

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[54] *See* Reyngold/Coopey Testimony at 13.

[55] *See* Revised Tariff Section 3.8(b), citing Revised Billing Policy Section 6.3.1.

[56] *See* Revised Billing Policy Section 6.3.1 (specifying that a Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party).

[57] *See* Reyngold/Coopey Testimony at 14.

[58] *See* Revised Tariff Section III, Appendix I, Form Cost-of-Service Agreement, Section 11.2 (Notices) and Exhibit B (ISO's Representatives).

- the elimination of provisions or portions of provisions that explicitly relate to Peak Energy Rent ("PER"),[59] which became inoperative on June 1, 2019 as a result of a Commission order accepting its elimination;[60] and

- several non-substantive formatting changes in Market Rule 1, Billing and Financial Assurance Policies.

One additional clarification warrants a slightly more detailed explanation. Financial Assurance Policy Section III.A(vii) describes the extent to which components of a Market Participant's positive and negative Financial Assurance Obligations may offset each other. The ISO is clarifying that payments and charges from Financial Transmission Right ("FTR") Financial Assurance Requirements cannot be used to offset the payments and charges from other Financial Assurance Obligations.[61] FTR Financial Assurance Requirements are calculated and handled separately from other Financial Assurance Obligations because of the different nature of the risk involved with those transactions, and thus should not be included in the existing financial assurance offset provisions.[62]

IV. STAKEHOLDER PROCESS

The Tariff revisions proposing, *inter alia*, to accelerate the settlement and billing of certain FCM charges and payments from a monthly to a daily settlement were considered through the complete NEPOOL Participant Processes, receiving the unanimous support of the NEPOOL Participants Committee. The NEPOOL Budget and Finance Subcommittee reviewed the portions of the FCM Acceleration Changes and RBA Changes related to the Billing and Financial Assurance Policies at its October 12 and November 29, 2021 teleconference meetings. No objections were raised to the changes that were ultimately forwarded to the Participants Committee.[63]

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[59] *See* Revised Tariff Section I.2.2 (removing definitions of Average Monthly PER, Hourly PER, Monthly PER, and Peak Energy Rent), Revised Tariff Section III.3.8(e) (removing exception that revised meter and internal bilateral transactions data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values), Revised Section III.13.2.4 (removing a provision that applied to the CCP beginning on June 1, 2019), Revised Tariff Section III.13.7.1 (removing an adjustment to account for PER), deleted Section III.13.7.1.2 (removing Peak Energy Rents calculation), deleted Section III.13.7.1.2.1 (removing Hourly PER calculation), deleted Section III.13.7.1.2.2 (removing Monthly PER application), Revised Tariff Section III.13.7.1.3 (removing PER adjustment to Export Capacity charge calculation), Revised Tariff Section III.13.7.5.1 (removing PER from definition of Net Regional Clearing Price and removing prohibition on a Self-Supplied FCA resource from receiving PER by self-supplying its CLO), Revised Tariff Section III.13.7.5.4.1 (removing PER adjustment from CTR calculation), Revised Tariff Section III, Appendix I, Schedule 3 (removing PER from calculation of the Revenue Credit for the Obligation Month).

[60] *See ISO New England Inc.*, Docket No. ER15-1184-000, (issued May 5, 2015) (FERC delegated letter order).

[61] *See* Revised Financial Assurance Policy Section III.A(vii).

[62] *See* Reyngold/Coopey Testimony at 9-10.

[63] The Budget & Finance Subcommittee is a non-voting subcommittee that provides input and advice to the ISO and the NEPOOL Participants Committee with respect, *inter alia*, to the ISO's Financial Assurance and Billing Policies.

At its November 9–10, 2021 meeting, the NEPOOL Markets Committee considered and, based on a voice vote in favor, unanimously recommended that the NEPOOL Participants Committee support the FCM Acceleration Changes, FCM Cost Allocation Changes, and Clean-up Changes. Subsequently, at its January 6, 2022, meeting, the NEPOOL Participants Committee unanimously approved all of the changes filed herein.[64]

V. REQUESTED EFFECTIVE DATE

The ISO respectfully requests that the Commission accept the Tariff revisions related to the Requested Billing Adjustment process[65] as filed, without suspension or hearing, to be effective on May 1, 2022, 60 days after filing.

For the balance of revisions proposed in this filing, the ISO requests an effective date of June 1, 2022. This effective date will ensure the changes apply for the CCP beginning on the same date, and is coincident with the FCM Cost Allocation Improvements implementation date.

By implementing the FCM Acceleration Changes on June 1, 2022, these changes will apply to FCM charges and payments, as well as Financial Assurance Obligations, for the Capacity Commitment Period that begins on that date. Importantly, charges and payments and attendant Financial Assurance Obligations for the month of May 2022 are not settled and billed until mid-June, with the monthly FCM bill being issued on June 13, 2022. Because those May 2022 charges and payments and attendant Financial Assurance Obligations accrue as part of the prior Capacity Commitment Period (*i.e.*, the June 1, 2021 through May 31, 2022 Capacity Commitment Period), before the effective date of the FCM Acceleration Changes, they will be subject to the existing monthly billing and FCM Financial Assurance Requirements for all FCM charges and payments, rather than the requirements that apply under the FCM Acceleration Changes.

VI. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[66] 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:

<u>35.13(b)(1)</u> – Materials included herewith are as follows:

- This transmittal letter;

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[64] An End User abstention by Mr. Samuel Mintz was recorded.

[65] Revised Tariff Section III.3.8(b) and Revised Billing Policy Sections 6.3.1, 6.3.2 and 6.5(a).

[66] 18 C.F.R. § 35.13 (2021).

- Testimony of Mark Wing, sponsored solely by the ISO;
- Joint Testimony of Kelly Reyngold and Kevin Coopey, sponsored solely by the ISO;
- Redlined Tariff sections effective May 1, 2022;
- Clean Tariff sections effective May 1, 2022;
- Redlined Tariff sections effective June 1, 2022;
- Clean Tariff sections effective June 1, 2022; 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 above, the ISO requests that the Tariff revisions filed herewith become effective on May 1, 2022.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

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

35.13(b)(5) – The reasons for this filing are discussed in Section III of this transmittal letter.

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

VIII. CONCLUSION

For the reasons set forth above, the Filing Parties respectfully request that the Commission accept the revisions filed here without condition or delay to become effective on May 1, 2022 and June 1, 2022, as described above.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket No. ER22-_____-000
	)	

TESTIMONY OF MARK WING
ON BEHALF OF
ISO NEW ENGLAND INC.

I. <u>WITNESS IDENTIFICATION</u>

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

A: My name is Mark Wing. I am a Supervisor in the Market Analysis & Settlements Department at ISO New England Inc. (the "ISO").[1] My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

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

A: I have been a Supervisor in the Market Analysis & Settlements Department since January 2019. My team's responsibilities include running settlements related to the ISO markets, verifying the accuracy of the settlement results, and performing complex analyses related to the ISO markets. Before becoming a supervisor, for 12 years I was a Business Analyst in the Market Analysis & Settlements Department. My responsibilities included analyzing changes to market rules and market designs, developing business requirements

[1] Capitalized terms that are not otherwise defined herein have the meanings ascribed to them in the ISO New England Transmission, Markets and Services Tariff (the "Tariff").

for the changes, and validating any software implementations. I joined the ISO in January 2000 as a programmer in the IT Department. I hold a B.S. and M.S. in Electrical Engineering from Western New England University.

II. PURPOSE AND BACKGROUND

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain the changes to the Forward Capacity Market ("FCM") settlement processes contained in the instant filing. These changes convert some monthly FCM payments and charges to a daily settlement.

Q: By way of background, please provide a high-level overview of the Forward Capacity Market.

A: The ISO administers the FCM to procure capacity from qualified resources on a three-year-forward basis. The ISO conducts a Forward Capacity Auction ("FCA") in which Resources are awarded a Capacity Supply Obligation ("CSO"). Resources with a CSO must deliver that capacity for each Obligation Month in the applicable Capacity Commitment Period ("CCP"). Each CCP spans from June 1st to May 31st of the following year. Before each CCP, the ISO runs three annual reconfiguration auctions which allow resources to increase or shed all or part of their CSO for the commitment period. Before each Obligation Month, the ISO runs a monthly reconfiguration auction allowing resources to increase or shed all or part of their CSO for the Obligation Month. Resources may also increase or shed CSO through monthly CSO bilateral transactions.

For each Obligation Month in the CCP, Market Participants receive payments based on each of their resources' CSO. These payments are charged to load-serving entities based upon their Capacity Load Obligation ("CLO"), which originates from their share of historic contributions to peak load, adjusted to reflect bilateral transactions and certain other specific allocations. These payments and charges are currently settled after the end of each Obligation Month, and Market Participants have financial assurance requirements until the charges are paid or payments are received.

III. <u>MODIFICATIONS TO THE CURRENT SETTLEMENT SCHEDULE</u>

Q: Please provide a general overview of the current market settlement and billing processes.

A: The ISO settles the various market products sub-hourly, hourly, or monthly depending upon the market. For example, real-time energy is settled sub-hourly, day-ahead energy is settled hourly, and the FCM is settled monthly.

The ISO issues bills to Market Participants twice weekly. Each bill includes the recent sub-hourly and hourly market settlements that are ready to be billed. Hourly and sub-hourly markets are typically billed three to eleven calendar days after the operating day. Charges for monthly markets are included in the bill issued on the first Monday (or Tuesday if Monday is a holiday) following the ninth calendar day of the following month.

Q: How is the Forward Capacity Market currently settled and billed?

A: The ISO has historically settled and billed the Forward Capacity Market monthly. This was largely because the original market design treated CSO as a monthly product and included many components collected after the end of the Obligation Month.

Q: How is the ISO revising the current settlement?

A: The ISO will convert a majority of the monthly FCM settlement payments and charges to a daily settlement.

Q: Why is it now possible to convert a majority of the Forward Capacity Market payments and charges to a daily settlement?

A: At the inception, many areas of the FCM settlement were dependent on information not available until after the operating month. As the FCM market design evolved, some concepts were phased out, such as equivalent planned outage hours and peak energy rents ("PER"). Other concepts such as cost allocation were improved. The FCM settlement is now less dependent on information collected after the operating month, therefore making it possible to convert most FCM payments and charges to a daily settlement without changing the market design.

Q: What are the benefits of this change?

A: Accelerating the settlement and billing of the FCM impacts the amount of financial assurance that is required from Market Participants. At the beginning of each month, the ISO assesses financial assurance for monthly markets based on the current month and all previously unbilled months. Due to the timing of the bill invoice, for approximately 15 days per month, Market Participants are required to provide financial assurance for two months of charges. For example, a Market Participant with net FCM charges for June and July will be required to post two months of financial assurance starting on July 1st and ending mid-July.

In addition, Market Participants with a CSO must currently wait between 45 and 50 days from the beginning of an Obligation Month to receive payment. For example, a Market Participant with a CSO for June will not receive payment until mid-July. Converting FCM to a daily settlement means Market Participants with a CSO start receiving their payments during the Obligation Month and Market Participants with load obligations have reduced financial assurance requirements. The Reyngold/Coopey Testimony also provided in support of this filing provides more detail on the calculation and timing of financial assurance requirements associated with the Forward Capacity Market and how the proposed changes will impact these requirements.

Q: Please describe how the ISO will calculate daily FCM settlement values going forward.

A: The ISO is proposing to convert payments and charges related to capacity to a daily settlement. At a high level, the ISO will determine the daily capacity payment for each day in the Obligation Month by calculating the capacity payment for the entire month and dividing it by the number of days in the month. The ISO will then allocate the resulting daily charges to Market Participants with a CLO. Specifically, the upcoming FCM Cost

Allocation changes[2] increase price transparency by separating the sources of capacity charges. The ISO will determine the daily capacity payment and charges for most of these sources. The FCM components that will be settled on a daily basis are associated with CSO transactions from the following activities:

- FCAs (including the substitution auction),
- annual reconfiguration auctions, monthly reconfiguration auctions and monthly CSO Bilaterals,
- HQ Interconnection Capability Credits,
- self-supply adjustments,
- Intermittent Power Resource Capacity adjustments,
- Multi-year rate election adjustments,
- CTR transmission upgrade charges, and
- CTR Pool-Planned Unit charges.

Q: Please provide an example detailing the daily calculation of FCM components.

A: FCA Payments: The ISO calculates FCA payments by multiplying the CSO megawatts ("MW") by the applicable clearing price. For example, a resource awarded a CSO of 75 MW, with an associated payment rate of $4 per kW-month, will receive a monthly payment of $300,000 (75 MW x $4 x 1,000). The ISO will calculate the resource's daily payment by dividing the monthly payment by the number of days in the month. As shown in the table below, if in June, the daily settlement value is $10,000, or $300,000

[2] These changes were approved by the Commission in 2018 but will be implemented on June 1, 2022. *See ISO New England Inc.*, Docket No. ER18-2125-000, (FERC delegated letter order issued September 26, 2018).

divided by 30 days. For July, the monthly payment would be divided by 31 days, resulting in a daily settlement amount of $9,677; and for February, the payment of $10,714 is based on 28 days.

Month	Monthly Payments	Days in Month	Daily Payments
June	$300,000	30	$10,000
July	$300,000	31	$9,677
February	$300,000	28	$10,714

<u>Charges and Adjustments</u>: Under FCM Cost Allocation changes that will become effective June 1, 2022, the ISO will calculate separate monthly charge and adjustment rates for each FCM component. This rate is multiplied by the Market Participant's CLO to derive the monthly charge. As an example, assume a participant has 100 MW of CLO in the month, and the associated monthly charge rate for FCA transactions is $3.60 per kW-month. The monthly FCA charge is $360,000 (100 MW x $3.60 x 1,000).

To determine a daily settlement value, the ISO will divide the monthly charge rate by the number of days in the month. In the example provided, for June, the charge rate of $3.60 will be divided by 30 days, resulting in a daily rate of $0.12 per kW-month. This value is then multiplied by the Market Participant daily CLO of 100 MW, and again multiplied by 1,000 to reflect that the payment is on a per-kW basis, resulting in a daily charge of $12,000 ($0.12 x 100 MW x 1,000). In July, a daily charge rate would be calculated using 31 days; in February, either 28 or 29 days would be used. The table below shows how certain charges would be calculated for different components in a month with 30 days.

Charge Type	Participant CLO MW	Days in Month	Charge Rate ($/kW-month)	Daily Charge
FCA	100	30	$3.60	($12,000)
MRA	100	30	$0.45	($1,500)
ARA	100	30	$0.60	($2,000)
Total Daily Charges				**($15,500)**

Q: Will any other values be converted to a daily basis?

A: Yes. The Zonal Capacity Obligation – a value derived from Market Participants' share of historic contributions to peak load and used in the FCM settlement – will be calculated daily. A daily value is necessary to support the daily settlement of the FCM payments and charges discussed in this filing.

Q: What FCM charges are not being revised as part of this filing?

A: Six FCM settlement components will continue to be settled monthly: forfeited financial assurance allocations; charges and payments associated with resources retained for reliability; Failure to Cover charges and payments; payments and charges associated with certain capacity export transactions; Capacity Performance Payments; and the allocation of excess revenues that may occur under certain circumstances. Settlements for these components are either infrequent, require information not available until after the Obligation Month, or are generally low amounts. The total of these payments and charges represent less than 1% of the total FCM Settlement.[3]

[3] *See* ISO New England, Accelerate Forward Capacity Market Settlement & Billing, presented to the NEPOOL Markets Committee at its September 13-14, 2021 meeting, at Slide 5, *available at* https://www.iso-ne.com/static-assets/documents/2021/09/2021_09_13_14_a06_accelerate_fcm_billing_and_settlement_proposed_revisions.pptx.

Q: Are there any other conforming changes needed to implement the proposed Forward Capacity Market daily settlement?

A: Yes. The deadline for Capacity Load Obligation Bilateral transactions to be included in the initial settlement will be moved to the first business day of the Obligation Month. Currently, the initial settlement includes Capacity Load Obligation Bilaterals submitted during the month and up to two business days after the end of the month. These transactions, which allow Market Participants to transfer Capacity Load Obligation to other Market Participants, are submitted on Obligation Month boundaries. If the initial daily settlements include Capacity Load Obligation Bilaterals entered during the Obligation Month, the contracts would not be included in all initial settlements. For example, if a contract was confirmed on the 15th day of the month and if the first ten days of the month had previously been settled, the first ten days of the contract would not be settled until the resettlement. As a result, the existing timeline can cause considerable challenges in the evaluation of financial assurance. Therefore, the ISO proposes to revise the initial settlement to include Capacity Load Obligation Bilaterals that have been submitted and confirmed by the first business day of the Obligation Month. Any Capacity Load Obligation Bilaterals submitted after the first day of the Obligation Month will be included during resettlement of the FCM, which occurs approximately three months after the initial settlement bill has been issued.

IV. <u>FCM COST ALLOCATION CLARIFYING CHANGES</u>

Q: Please describe the changes that the ISO is proposing to make to the FCM cost allocation rules in Market Rule 1.

A: By way of background, in 2018, the ISO revised the cost allocation methodology to align with the use of sloped demand curves (known as MRI-based demand curves). As part of the same project, the ISO increased transparency by eliminating the use of a zonal blended rate for cost allocation purposes (the Net Regional Clearing Price) and, instead, proposed to separately calculate and allocate each of the discrete charges and adjustments reflected in a blended rate. The Commission approved these changes in 2018. The ISO has been working to implement these changes and has discovered that several portions of the Tariff would benefit from additional refinement before implementation on June 1, 2022.

The ISO is now proposing five discrete clarifying changes to the cost allocation provisions.

Q: Please explain the clarifying changes that are included as part of this filing.

A: First, in Section III.13.7.5.1.1.6, the formula to calculate the charge rate for the Intermittent Power Resource capacity adjustment includes the Total Zonal Capacity Obligation in the denominator, which is currently described in that section as "*the total Capacity Load Obligation* in all Capacity Zones." (emphasis added) In one place, the calculation uses an existing term that is incorrect, and the ISO is revising this to use "*total Zonal Capacity Obligation* in all Capacity Zones." (emphasis added) This change accurately captures the correct term.

Second, in Section III.13.7.5.1.1.9, the ISO is proposing to clarify that the CTR Pool-Planned Unit Charge is allocated on a system-wide basis. The current Tariff language is not clear that the allocation is system-wide rather than zonal, and the ISO proposes to correct this by explicitly stating the allocation is to total CLO.

Third, in Section III.13.7.5.1.1.10, the Failure to Cover Adjustment is allocated to Market Participant CLO – a monthly value. However, the same Section indicates that Zonal Capacity Obligation – a daily value that is unlikely to equal the monthly CLO – is used to calculate the rate. The ISO is revising the Tariff to use total CLO as the denominator in this rate calculation, to correctly reflect the monthly CLO value.

Fourth, in Section III.13.7.5.2, the ISO is replacing lower case language describing how Coincident Peak Contribution values are determined with the defined term "Coincident Peak Contribution."

Fifth, in Section III.13.7.5.4.5, the Specifically Allocated CTRs for Pool-Planned Units calculation currently uses the most recent seasonal claimed capability value. The FCM settlement currently includes a payment to Specifically Allocated CTRs for Pool-Planned Units based on the CSO amount awarded to the resource in the applicable FCA. The CSO, in turn, is based upon recent seasonal claimed capability values *at the time of qualification*. The ISO therefore proposes to revise the language to clarify that the calculation reflects the seasonal claimed capability values at the time of qualification.

V. EFFECTIVE DATE OF THE PROPOSED CHANGES

Q: Please explain why the ISO is proposing a June 1, 2022 effective date.

A: This date is concurrent with the start of the next CCP. In addition, the previously-approved FCM Cost Allocation Improvements changes will be effective as of the same date.

VI. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

Executed on March 2, 2022

Mark Wing

Mark Wing, ISO New England Market Analysis & Settlements Department

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket No. ER22-_____-000
	)	

JOINT TESTIMONY OF KELLY REYNGOLD AND KEVIN COOPEY
ON BEHALF OF ISO NEW ENGLAND INC.

I. <u>WITNESS IDENTIFICATION</u>

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

A: *Ms. Reyngold:* My name is Kelly Reyngold. I am the Controller in the Financial and Compliance Department at ISO New England Inc. (the "ISO").[1] My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Mr. Coopey: My name is Kevin Coopey. I am a Supervisor in the Finance and Market Risk Department at the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

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

A: *Ms. Reyngold:* I joined the ISO in June of 2002 and have been Controller since 2011. In this role, I am responsible for administering the ISO New England Billing Policy ("Billing Policy"). I am also responsible for overseeing Treasury

[1] Capitalized terms that are not otherwise defined herein have the meanings ascribed to them in the ISO New England Transmission, Markets and Services Tariff (the "Tariff").

management, Procurement, Payroll, and all financial/accounting functions. Prior to joining the ISO, I held various financial positions in both publicly and privately held corporations and public accounting firms. I hold a B.S. in Accounting from Bentley University and I am a Certified Public Accountant.

Mr. Coopey: In my current position, which I have held since October 2021, I manage a team of professionals tasked with the daily administration of the ISO New England Financial Assurance Policy ("Financial Assurance Policy"). I joined the ISO in 2011 as a Market Operations Analyst, and in 2015 became a Lead Market Analyst supporting the ISO's Market Development team. Prior to joining the ISO, I worked in power marketing; I was a Senior Analyst at DTE Energy Trading from 2010 to 2011, and a Pricing Analyst at Pepco Energy Services from 2008 to 2009. I started my career in power markets in 2007 as a Research Analyst at Pace Global Energy Services. I hold a Master's of Science degree in Finance from the University of Illinois at Urbana-Champaign and a Bachelor's of Science degree in Energy, Business, and Finance from The Pennsylvania State University.

Q: What is the purpose of your testimony?

A: The purpose of our testimony is to explain the proposed Billing Policy changes to accelerate the billing of certain Forward Capacity Market ("FCM") payments and charges currently settled on a monthly basis to a daily settlement. As a result of those changes, we will explain how the ISO will also revise Market Participant

Financial Assurance Obligations in the Financial Assurance Policy. Our testimony also addresses changes that we are proposing to the ISO's Requested Billing Adjustment ("RBA") policy.

II. OVERVIEW OF CURRENT BILLING AND FINANCIAL ASSURANCE PROCEDURES FOR FCM MONTHLY CHARGES

Q: Please provide an overview of the ISO's current billing process.

A: The Billing Policy defines the billing and payment procedures utilized in administering the charges and payments due under the Tariff and the ISO Participants Agreement. The ISO currently settles and bills most FCM charges on a monthly basis, which are defined as Non-Hourly Charges. Non-Hourly Charges currently include charges relating to the monthly markets, the Forward Capacity Market and other ancillary services, as well as other charges that are not relevant to the changes the ISO is proposing in this filing. Currently, both FCM payments and charges are settled and billed monthly. As a result, the related Financial Assurance Obligations are calculated based on monthly settlement values.

Other charges and payments are settled and billed more frequently, and are defined as Hourly Charges in the Tariff and Billing Policy. These include each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy, as well as for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, and Net Commitment Period Compensation. Some of these charges are settled sub-hourly, some hourly, and some daily, and all are billed twice weekly.

Q: Please provide an overview of the current Financial Assurance Obligations related to payments and charges in the Forward Capacity Market.

A: Any Lead Market Participant transacting in the FCM must provide the FCM Financial Assurance Requirements described in Section VII of the Financial Assurance Policy. FCM payments from Market Participants with Capacity Supply Obligations are incorporated into the FCM Delivery Financial Assurance Requirement in the monthly capacity charge ("MCC") value. The MCC equals Monthly Capacity Payments incurred in previous months, but not yet billed. In short, as described in Section VII.A of the Financial Assurance Policy, the payment due to the participant as a result of a Capacity Supply Obligation for the prior month serves as a credit against financial assurance obligations incurred from participating in the market until the monthly bill issued.

FCM charges from Market Participants with Capacity Load Obligations are collateralized through FCM Capacity Charge Requirements as described in Section VII.C of the Financial Assurance Policy. FCM Capacity Charge Requirements for each Market Participant with a Capacity Load Obligation are the product of the Estimated Capacity Load Obligation and the FCM Charge Rate for the applicable Capacity Zone for the current month and all previously unbilled months. Therefore, a participant with a Capacity Load Obligation will have a financial assurance obligation until those charges are billed and collected. In the existing design the billing and collection is on a monthly basis.

Q: Generally, why is the ISO proposing to accelerate the billing of FCM payments and charges?

A: At the May 10, 2019 NEPOOL Budget and Finance Subcommittee meeting, a Market Participant asked the ISO to assess whether the FCM settlement and billing cycle could be accelerated. The ISO formed a working group to perform the assessment, which ultimately recommended that the acceleration proposal was feasible and should move forward given the benefits it would produce.

Q: Please describe those benefits.

A: Accelerating the FCM settlement and billing cycle will reduce overall risk of default for the ISO New England market by accelerating the settlement, billing, and cash clearing of the majority of the dollars in the FCM. Put simply, by accelerating the settlement and billing of the FCM, a Market Participant's obligations come due more frequently, rather than allowing those obligations to accrue or build up over an extended period of time (*i.e.*, the entire month) before payment is due. In other words, under the proposed method of accelerating the settlement and billing cycle, actual cash is transferred much more quickly to and from each party. More frequent settlement and billing alleviates the existing large build-up of obligations for charges that have been incurred (currently between

30-45 days worth) resulting in a much smaller amount of unpaid charges (7-16 days' worth) that are at risk of a potential default.

In addition, from a participant's perspective, these changes reduce financial assurance that was previously necessary due to the length between incurring a FCM obligation and the time when those obligations are billed and ultimately collected. Accelerating the billing of a majority of FCM charges and payments will also reduce the need for uneven collateral amounts as a result of fluctuating monthly FCM obligations. Under the proposal, participant collateral obligations will remain more consistent and at a lower level, due to the elimination of up to 45 of accumulated payments and charges that currently occurs before billing and collection. This reduction in aggregate financial assurance will lower Market Participant Financial Assurance Obligations and free up capital for the participants that could be used for other purposes.

Q: How does accelerating the settlement and billing of the FCM reduce the amount of financial assurance that Market Participants are required to maintain?

A: As discussed above, because obligations will come due more frequently under the proposal, rather than accrue for an extended period of time, the amount of financial assurance required to cover any given obligation will be reduced as well. To take a very simple example, if a Market Participant accrues a $10,000 bill arising from FCM activities in a month, then, conceptually, $10,000 in obligations must be collateralized. If, instead, that $10,000 bill is broken up into ten separate $1,000 bills, each coming due over the course of the month as each obligation arises, then only $1,000 needs to be collateralized at any given time. As a result of these changes, the ISO estimates that FCM Financial Assurance Requirements will be reduced by approximately 75%.

Q. Does decreasing the amount of financial assurance required for FCM obligations potentially increase any risk to the market?

A. No. This decrease in financial assurance does *not* increase risk. The proposed design uses the same basic methodology for calculating financial assurance as exists today. Under both the current methodology and the proposed methodology, the quantity of financial assurance that a participant must hold is calculated to cover outstanding obligations from the current period and all previously unbilled periods.

As discussed above, rather than increase risk to the market, these changes will ultimately lessen overall default risk to the ISO New England Market because cash will clear through the ISO more quickly. Changing certain FCM payments and charges to a daily settlement will result in smaller increments of obligations (*e.g.*, today the affected FCM payments and charges accumulate on average up to 45 days; the proposed changes reduce this to an accumulation on average of 7-16 days). Because billing and collection will occur more frequently, participants owed FCM payments will be paid much closer to the date of their performance, and participants owing FCM charges will pay much closer to the date of their obligation. Consequently, any potential defaults will be realized, and can be addressed, more quickly due to the accelerated billing schedule. Converting the majority of large monthly obligations to settle instead on a daily basis will ultimately decrease the ISO's reliance on financial assurance as the ultimate backstop for these obligations.

III. MODIFICATIONS TO FINANCIAL ASSURANCE OBLIGATIONS AND BILLING PROCEDURES TO ENABLE DAILY SETTLEMENT AND MORE FREQUENT BILLING

Q: How is the ISO revising the Billing Policy to account for the new daily charges?

A: The FCM settlement payments and charges that will be settled on a daily basis will be captured in the Billing Policy with a new defined term: "Daily FCM Charges." The Daily FCM Charges will be included as part of the Hourly Charges, which are addressed in Section 1.3 of the Billing Policy, and as such will follow the same billing schedule. FCM related charges that will continue to settle on a monthly basis will be defined as "Monthly Forward Capacity Market Charges and Payments," and will continue to be covered under the Non-Hourly Charge provisions in Section 1.3 of the Billing Policy.

Q: How is the ISO revising the Financial Assurance Policy to account for the new daily charges?

A: In order to account for the payments and charges from the new daily FCM settlements, the ISO will add a new term, Daily FCM Requirements, to each

Market Participant's FCM Financial Assurance Requirements. A Market Participant's Daily FCM Requirements will comprise three components: 1) Unpaid daily FCM charges, including daily FCM charges that have been invoiced but not paid (which amount shall not be less than zero); 2) Unbilled daily FCM charges, including daily FCM charges that have been settled but not invoiced; and 3) the Daily FCM Obligation Estimator. By incorporating FCM daily credits for both the prior and current month, the methodology yields a more accurate estimate of obligations, because these obligations can fluctuate over different monthly periods.

Q: Please elaborate on the third component, the Daily FCM Obligation Estimator.

A: This component estimates daily FCM charges that have accrued to a participant but have not yet been settled. To estimate this value, the Daily FCM Obligation Estimator calculates a weighted average of FCM daily payments for prior and current months, the latest settled FCM daily charges for each participant, as well as an FCA price ratio. The FCA price ratio is designed to produce a weighted average commitment period price for the unsettled period in the event that period spans two Capacity Commitment Periods (where each of those periods has a different FCA clearing price). If all of the days included in the Daily FCM Obligation Estimator fall within the same Capacity Commitment Period, the price ratio will equal 1.0 and the price will be determined based on the relevant single FCA clearing price.

Q: Please provide an example illustrating how the proposed revisions will impact the Financial Assurance Obligations for a hypothetical participant.

A: The following analysis compares FCM Financial Assurance Obligations from the current design and the proposed design. As discussed above, payments owed to Market Participants with Capacity Supply Obligations and charges due from Market Participants with Capacity Load Obligations net against the participant's total financial assurance obligations through separate sections of the Financial Assurance Policy. Specifically, the payments owed to a Market Participant with Capacity Supply Obligations offset the collateral requirements for capacity delivery that are specified as FCM Delivery Financial Assurance in Section VII.A of the Financial Assurance Policy. The payments due from Market Participants with Capacity Load Obligations have their capacity market charges collateralized as FCM Capacity Charge Requirements in Section VII.C of the Financial Assurance Policy. Under the proposal, the daily financial assurance obligations for Capacity Load Obligations will be captured in the new Daily FCM Requirements methodology, and the FCM charges that will remain monthly capacity charges will continue to be collateralized through FCM Delivery Financial Assurance, which is covered under Section VII.A of the Financial Assurance Policy.

In the example below, under the current design, a 100 MW Capacity Load Obligation portfolio is estimated to incur FCM Financial Assurance Obligations of $1.414 million and $0.707 million respectively, before and after the monthly bill is issued. These figures will drop to \$0.236 million under the proposed design. This example illustrates both the reduced financial assurance obligation from daily settlement and billing as well as the leveling effect that daily billing provides (*i.e.*, there is no longer a large peak of financial assurance at the culmination of the billing cycle).

Financial Assurance for 100 MW Capacity Load Obligation (\$1000)				
	Current Design	Proposed Design	Change (\$)	Change (%)
Before Monthly Bill is Issued	\$1,414	\$236	\$1,178	83%
After Monthly Bill is Issued	\$707	\$236	\$471	67%

In the next example, under the current design, a 100 MW Capacity Supply Obligation portfolio will have a credit of \$0.703 million from the start of the month until the monthly bill is issued, and \$0 as soon as the monthly bill is issued, representing the prior month's settlement and cash clearing of the Capacity Supply Obligation owed to the Participant. Under the proposed design, the financial assurance credits for the Capacity Supply Obligation portfolio will be calculated on a daily basis (*e.g.*, \$0.0047) and will consistently accrue at this lower level, which illustrates the impact of more frequent billing and actual cash clearing using the daily values. This example also shows that that the participant supplying capacity will not have to wait up to 45 days to be paid for their ongoing daily performance.

Financial Assurance for 100 MW Capacity Supply Obligation (\$1000)				
	Current Design	Proposed Design	Change (\$)	Change (%)
Before Monthly Bill is Issued	(\$703)	(\$47)	(\$656)	93%
After Monthly Bill is Issued	\$0	(\$47)	\$47	N/A

Q: Is the ISO proposing any other changes to the Financial Assurance Policy as part of this filing?

A: Yes. The ISO is proposing to eliminate Section VII.C of the Financial Assurance Policy. In its current form, this provision establishes the collateral requirement for market obligations arising from Capacity Load Obligations. The collateralization requirement is calculated by multiplying the Estimated Capacity Load Obligation by the FCM Charge Rate. The revised financial assurance obligations for Capacity Load Obligations will be captured in the new Daily FCM Requirements formula described above. At the same time, the FCM charges that will remain monthly capacity charges will continue to be collateralized through FCM Delivery Financial Assurance, which is covered under Section VII.A of the Financial Assurance Policy. As a result, Section VII.C is no longer operative and the ISO is proposing to delete it and reserve it for future use.

In addition, the ISO is proposing to clarify Section III.A of the Financial Assurance Policy. This provision describes the extent to which components of a Market Participant's positive and negative Financial Assurance Obligations may offset each other. The ISO is clarifying that payments and charges from Financial Transmission Right ("FTR") Financial Assurance Requirements cannot be used to offset the payments and charges from other Financial Assurance Obligations. Generally, the purpose of financial assurance is to cover a participant's market obligations in the event of a default. FTRs, in contrast, are financial instruments that a Market Participant has the option to buy to help hedge against the economic impacts associated with transmission congestion and to arbitrage differences between expected and actual day-ahead congestion caused by constraints on the transmission system. FTR Financial Assurance Requirements are calculated and handled separately from other Financial Assurance Obligations because of the different nature of the risk involved with those transactions. Accordingly, FTR Financial Assurance Requirements should not be included in the existing financial assurance offset provisions. Maintaining separate FCM and FTR Financial Assurance Requirements is a conservative approach and one that the ISO considers to be a best practice.

IV. <u>REVISIONS TO REQUESTED BILLING ADJUSTMENT PROCESS</u>

Q: Please describe the current Requested Billing Adjustment process.

A: The current Billing Policy Section 6.3.1, requires Market Participants to submit Requested Billing Adjustments to the ISO's Chief Financial Officer. Importantly, the Billing Policy does not prescribe the method of delivery for these requests and as such currently receives Requested Billing Adjustments via email. The current policy also does not require the ISO to acknowledge receipt of the request.

Q: Generally, why is the ISO proposing these changes?

A: Over the last several years the ISO has been implementing tighter cybersecurity controls including for email. ISO cybersecurity best practices discourage opening attachments from unknown parties, and external emails sent from unrecognized email addresses are more likely to be flagged as Spam. If an email is flagged as

Spam or is inadvertently deleted by the recipient, the sender does not receive any notification that the email was not delivered or received.

Q: Please explain the changes that are proposed to the method of delivery and confirmation of receipt as part of this filing.

A: The revisions will direct Requested Billing Adjustments to be submitted to Participant Support and Solutions at the ISO via its support system (AskISO), the ISO’s established and centralized online platform to customer inquiries. The proposed changes will allow for consistency and structure around submittal, provide acknowledgement of receipt, and reduce cybersecurity risk.

V. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

Executed on March 2, 2022

Kelly Reyngold

Kelly Reyngold, ISO New England Financial and Compliance Department

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

Executed on March 2, 2022

Kevin Coopey

Kevin Coopey, ISO New England Finance and Market Risk Department

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 -General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases and Net Commitment Period Compensation (all such hourly charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the Forward Capacity Market and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 -Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 -Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 -TIMING AND CONTENT OF STATEMENTS.

Section 2.1 - Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 -Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 - Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 -Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Capacity Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of capacity charges, penalties and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 - <u>Monthly Statements for Transmission Charges</u>. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 –<u>Certain Subsequent Adjustments to Previously Issued Statements.</u>

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	**Corrected Data Must be Submitted By**
Adjustments to Monthly Regional Network Load Submissions	20^{th} day of the fourth (4^{th}) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 -PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 -Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4 (for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 -<u>ISO Payment of Remittance Advice Amounts</u>. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by

11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance

Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance

Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a "Congestion Shortfall"), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an "Unsecured Municipal Market Participant") and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the "Default Period"), pro rata based on the ISO Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant's Market Credit Limit under the ISO New England Financial

Assurance Policy (such total amount of reduced Payments being referred to as the “Unsecured Municipal Default Amount”). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period’s Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO’s single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant

Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) *Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal

Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of

Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy all times during that calendar year.

h) Reduction of Payments and Increases in Transmission Charges for Other Covered Entities.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the "Unsecured Transmission Default Amount") for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the "Uncovered Transmission Default Amount"). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving

Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) *Order of Settlement.*

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any 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 (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such

Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section 3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -<u>Payment Default Shortfall Fund Account.</u> Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -<u>Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures.</u> Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – ––ISO Review of Requested Billing Adjustment.

Section 6.3.1 – ––Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to ~~the Chief Financial Officer of the ISO~~Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – ––Notice of ISO Review of Requested Billing Adjustment. Within three Business Days of the receipt by ~~the ISO's Chief Financial Officer~~ ISO Participant Support and Solutions of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – —ISO Review of Requested Billing Adjustments. The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – —Comment Period. Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – —ISO Action on Requested Billing Adjustment. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an

"Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – –Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – –Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – ––Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association (“AAA”). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO’s designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – ––Finality of the AAA Neutral’s Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – ––Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO (“Confidential Information”) shall be made available under these billing dispute procedures only to “Dispute Representatives” who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto (“Confidentiality Agreement”). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions ~~the Chief Financial Officer of the ISO~~ required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable

ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the Dispute Representative who are entitled to receive Confidential Information.

Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer. The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment _________________

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to ________________________ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment ______ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
   a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
   b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
   c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
   d. The Recipient acknowledges that any violation o0f this Agreement may subject the Recipient to civil actions for violation thereof.
   e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _________________________	By:_________________________
Dated:_______________________	Dated:________________________

III.3 Accounting And Billing

III.3.1 Introduction.

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

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

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

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

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

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

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

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this

calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

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

(g) **<u>Real-Time Energy Market Charge/Credit Excluding Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **<u>Real-Time Energy Market Charge/Credit For Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load

Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

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

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

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

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

(n) **<u>Non-Market Participant Loss</u>** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **<u>Inadvertent Energy Revenue</u>** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **<u>Inadvertent Energy Revenue Charges or Credits</u>** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy

quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

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

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

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

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

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

III.3.6.2 Eligible Data.

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

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

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

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

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

III.3.7 Eligibility for Billing Adjustments.

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

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

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

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

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

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

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) -Within three Business Days of the receipt ~~by the ISO's Chief Financial Officer~~ of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 -General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases and Net Commitment Period Compensation (all such hourly charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the Forward Capacity Market and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 -Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 -Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 -TIMING AND CONTENT OF STATEMENTS.

Section 2.1 - Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 -Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 - Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 -Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Capacity Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of capacity charges, penalties and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 - Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 –Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	Corrected Data Must be Submitted By
Adjustments to Monthly Regional Network Load Submissions	20th day of the fourth (4th) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 -PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 -<u>Invoice Payments.</u>

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4 (for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 -ISO Payment of Remittance Advice Amounts. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by

11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the “Default Amount”), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the “NEPOOL GIS”) before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the “NEPOOL GIS Administrator”) for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance

Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance

Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a “Congestion Shortfall”), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an “Unsecured Municipal Market Participant”) and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the “Default Period”), pro rata based on the ISO Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant’s Market Credit Limit under the ISO New England Financial

Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Default Amount"). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant

Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) *Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal

Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of

Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy all times during that calendar year.

h) Reduction of Payments and Increases in Transmission Charges for Other Covered Entities.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the "Unsecured Transmission Default Amount") for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the "Uncovered Transmission Default Amount"). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving

Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) *Order of Settlement.*

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any 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 (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such

Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section 3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -<u>Payment Default Shortfall Fund Account.</u> Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -<u>Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures.</u> Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – ISO Review of Requested Billing Adjustment.

Section 6.3.1 – Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – Notice of ISO Review of Requested Billing Adjustment. Within three Business Days of the receipt by ISO Participant Support and Solutions of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – ISO Review of Requested Billing Adjustments. The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – Comment Period. Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – ISO Action on Requested Billing Adjustment. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the Dispute Representative who are entitled to receive Confidential Information. Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer.

The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment _________________

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to ________________________ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment ______ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
    a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
    b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
    c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
    d. The Recipient acknowledges that any violation o0f this Agreement may subject the Recipient to civil actions for violation thereof.
    e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _________________________	By:__________________________
Dated:_______________________	Dated:________________________

III.3 Accounting And Billing

III.3.1 Introduction.

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

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

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

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

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

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

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets 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) <u>**Real-Time Energy Market Obligations For Demand Response Resources**</u>

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) <u>**Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions**</u> – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this

calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **<u>Real-Time Energy Market Deviations For Demand Response Resources</u>**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

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

(g) **<u>Real-Time Energy Market Charge/Credit Excluding Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **<u>Real-Time Energy Market Charge/Credit For Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load

Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

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

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

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

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

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

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

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy

quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

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

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

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

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

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

III.3.6.2 Eligible Data.

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

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

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

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

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

III.3.7 Eligibility for Billing Adjustments.

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

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

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

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

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

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

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

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

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

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

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

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

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.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

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

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

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

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

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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

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

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

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

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

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

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

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 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 Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

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.

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 established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

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

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

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

Capacity 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 as described in Section III.13.7.5.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

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

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

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

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

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

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

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

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

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 Capacity Commitment Period, 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. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

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

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

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

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

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

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

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

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

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

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

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

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

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

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

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

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

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

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

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

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

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.

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

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

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

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

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

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

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

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

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

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

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

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

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction 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 Demand Reduction 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 Demand Reduction Offer Block-Hours.

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

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

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

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

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

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

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

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or

Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

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

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

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

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

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

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a

Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, 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 Operating Procedures and Manuals.

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

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

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

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

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility’s Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

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

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

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

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

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

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

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

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

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

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

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

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

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

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

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

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

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

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

EMS is energy management system.

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

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

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

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

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

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

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

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

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

Energy Offer Floor is negative $150/MWh.

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

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

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

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

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

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

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

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

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

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

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

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

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

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

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

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

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

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

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

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

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

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

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

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process 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 Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Forward Reserve Offer Cap is $9,000/megawatt-month.

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

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

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

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

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

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

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

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

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

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

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

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

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

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

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

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

Governance Participant is defined in the Participants Agreement.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

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

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

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

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

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

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

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

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

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

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

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

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

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

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

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

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

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

ISO means ISO New England Inc.

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

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

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

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

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

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

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

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

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

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

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

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

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

ITC Agreement is defined in Attachment M to the OATT.

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

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

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

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

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

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

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

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

Limited Energy Resource means a Generator Asset 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. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

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

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

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

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

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

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

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

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

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

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

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

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

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

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

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

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

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

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

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

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

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

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

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

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

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

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.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

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

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

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

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

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

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

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

Market Participant 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 a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

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

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

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

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

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

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

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

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

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

MEPCO Grandfathered Transmission Service Agreement (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.

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

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

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

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

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

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

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

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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

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

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

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

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

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

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

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

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

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

MUI is the market user interface.

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

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

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

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

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

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

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

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

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

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

NEPOOL Participant is a party to the NEPOOL Agreement.

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

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

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

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

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

Network Customer is a Transmission Customer receiving RNS or LNS.

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

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

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

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

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

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

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

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

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

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

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

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

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

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

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

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

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

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

NMPTC means Non-Market Participant Transmission Customer.

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

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

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 Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset 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 Generator Asset is scheduled in the New England Markets.

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

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

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

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of 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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

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

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

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

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

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

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

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

Operations Date is February 1, 2005.

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

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

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

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

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

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

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

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

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

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

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

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

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

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

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

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

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

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

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

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

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

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

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

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

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

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

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

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

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 Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

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

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

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

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

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

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

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

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

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

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

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

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

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

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

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

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

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

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

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

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

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

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

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

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

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

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement 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 described in Section III.1.7.19 of Market Rule 1.

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

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

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

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

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 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 Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

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 Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

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

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

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 officer.

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.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

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).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

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

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

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market

Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart 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 Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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 Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

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

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

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

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

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

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

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

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

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

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

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

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

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

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

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.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

<u>Overview</u>

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the “RNA”), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term “Market Participant” shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement (excluding FTR Financial Assurance Requirements).

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);
(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or
(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, 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 officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market

Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

C. Ongoing Review and Credit Ratings

1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, 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, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

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

2. Unrated Market Participants

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is 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; "Debt-to-Total Capitalization Ratio" on any date is 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; and "EBITDA-to-Interest Expense Ratio" on any date is 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. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

3. Information Reporting Requirements for Market Participants

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm,

then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Market Credit Limits

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

1. Market Credit Limit for Non-Municipal Market Participants

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

a. Market Credit Limit for Rated Non-Municipal Market Participants

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of 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 ("TADO").

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%

Below BBB-	Below Baa3	0.00%

An entity's "Tangible Net Worth" for purposes of the ISO New England Financial Assurance Policy on any date 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.

b. Market Credit Limit for Unrated Non-Municipal Market Participants

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

2. Market Credit Limit for Municipal Market Participants

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

E. Transmission Credit Limits

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

1. Transmission Credit Limit for Rated Non-Municipal Market Participants

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

2. Transmission Credit Limit for Unrated Non-Municipal Market Participant

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

3. Transmission Credit Limit for Municipal Market Participants

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t =	The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;
n =	The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;
HC =	The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and
LMP ratio =	The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

FCA_Price_Ratio = (((Clearing Price_CCP_n x NDAY_P2_CCP_n) + (Clearing Price_CCP_{n+1} x NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing Price_CCP_n)

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

~~(ii)~~(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for ~~capacity transactions~~the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(~~iii~~iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;~~.~~

(~~i~~v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus

~~a.~~b. such Market Participant's Daily FCM Requirements; plus

~~b.~~c. such Market Participant's Virtual Requirements; plus

~~c.~~d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus

~~d.~~e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus

~~e.~~f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus

~~f.~~g. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

2. Notices

a. 80 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

b. 90 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

c. 100 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market

Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90 percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit

Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

3. Suspension from the New England Markets

a. General

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

b. Load Assets

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

c. FTRs

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

d. Virtual Transactions

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

e. Bilateral Transactions

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market

Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

MW_g = Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

Hr_{DA} = The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

D = The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

S_2 = The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

T = $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: MW_t = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

S_{2-3} = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_1 \times LF \times Hr_{MIS} \times (EP + S_{2-3}) \times 3.25) + (MW_l \times Hr_{MIS} \times TC \times 3.25)$$

Where:

MW_l = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

S_{2-3} = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per MW_1 assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

E = (SE) x 3.25

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

A. Ongoing Financial Review and Credit Ratings

1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

2. Unrated Non-Market Participant Transmission Customers

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

B. NMPTC Credit Limits

1. NMPTC Market Credit Limit

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%

AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

2. NMPTC Transmission Credit Limit

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%

A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

3. NMPTC Total Credit Limit

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

C. Information Reporting Requirements for Non-Market Participant Transmission Customers

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market

Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm,

then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Financial Assurance Requirement for Non-Market Participant Transmission Customers

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

1. Financial Assurance for ISO Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

2. Financial Assurance for Transmission Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers (“Designated FTR Participants”) are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the “FTR Financial Assurance Requirements”).

A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide “FTR Settlement Risk Financial Assurance” for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

B. Unsettled FTR Financial Assurance

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial

Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a “Designated FCM Participant”), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the “FCM Financial Assurance Requirements”). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant’s FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant’s Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero. FCM Delivery Financial Assurance is calculated according to the following formula:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF x DF] – MCC

Where:

MCC (monthly capacity charge) equals monthly capacity payments ~~Monthly Capacity Payments~~ incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June	2.000;
December and July	1.732;

January and August	1.414;
All other months	1.000.

DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to \$5.737(on a \$/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the "Non-Commercial Capacity FA Amount");

(ii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the next annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was awarded, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to two (2) times the Non-Commercial Capacity FA Amount; and

(iii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was accepted, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.

b. Non-Commercial Capacity Participating in the Ninth Forward Capacity Auction and All Forward Capacity Auctions Thereafter

A Designated FCM Participant offering Non-Commercial Capacity into the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:

NCC = the Capacity Supply Obligation awarded in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

    (i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

    (ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the

ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. ~~FCM Capacity Charge Requirements~~[Reserved for Future Use]

~~The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the FCM Charge Rate for the applicable Capacity Zone. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning prior to June 1, 2022 for a Capacity Zone will be calculated using the same methodology described in Section III.13.7.5 of Market Rule 1 for deriving the Net Regional Clearing Price, with the exception that the FCM Charge Rate will include the balance of the CTR fund after the value of specifically allocated CTRs has been paid, as described in Section III.13.7.5.3.1 of Market Rule 1. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning on or after to June 1, 2022 for a Capacity Zone will be calculated as the sum of the charge and adjustment rates specified in Section III.13.7.5.1.1 of Market Rule 1.~~

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance for Annual Reconfiguration Transactions

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in

Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy or the form of Control Agreement posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Requirements for Banks

Each bank issuing a letter of credit that serves as additional financial assurance must meet the requirements of this Section X.B.1. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers." The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly. To be included on the List of Eligible Letter of Credit Issuers, the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank and either: (i) be recognized by the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's or "A-" by Fitch so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer as described in clause (i) above; or (iii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch and be approved by the ISO in its sole discretion (the ISO will promptly advise the NEPOOL Budget and Finance Subcommittee of any additional bank approved by it under this provision). Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses if any applicable rating from the Rating Agencies falls below the levels listed in those clauses. In addition, no Posting Entity may provide a letter of credit that has been issued or confirmed by a bank that is an Affiliate of that Market Participant. If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy any of the criteria set forth above, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure to replace the letter of credit with a letter of credit from a bank satisfying those criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. In the case of a bank that is removed from CME list of approved letter of credit banks, the ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. No letter of credit bank may issue or confirm letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued or confirmed by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance

Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue or confirm letters of credit in favor of the ISO, (C) any letters of credit issued or confirmed by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued or confirmed by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.1.

Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.

2. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a Letter of Credit in the Form of Attachment 2, or (b) December 31, 2021. Any letter of credit provided for a new Posting Entity must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing a cash deposit in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of the cash deposited by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing a cash deposit or letter of credit in accordance with this Section X but shall not be satisfied through the provision of the cash deposit described in this Section X.C. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of the cash deposit initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that cash deposit to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: 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 Principals imposed 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; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

B. Weekly Payments

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the

Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

C. Use of Transaction Setoffs

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market

Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

D. Reimbursement of Costs

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

E. Notification of Default

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

F. Remedies Not Exclusive

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

G. Inquiries and Contests

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

H. Forward Contract/Swap Agreement

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

ATTACHMENT 1
SECURITY AGREEMENT

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____________], 20[_], by and between [INSERT NAME], a [_____________], having its principal office and place of business at [_________________________] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

    a. In this Security Agreement:

        i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

        ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

        iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. “Tariff” shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. “Obligations” shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. “Market Participants” shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor’s Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor’s obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party’s security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor’s organization documents verifying its correct legal name or, at Secured Party’s election, shall permit the Secured Party to obtain such certified copy at Debtor’s expense. From time to time at Secured Party’s election, the Secured Party may obtain a certified copy of Debtor’s organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor’s expense, to verify Debtor’s compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an “Event of Default” hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: ___________________________

Name:

Title:

ISO NEW ENGLAND INC.

By:___________________________

Name:

Title:

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] (“ACCOUNT PARTY”) IN FAVOR OF ISO NEW ENGLAND INC. (“ISO” OR “BENEFICIARY”) (“STANDBY LETTER OF CREDIT”).

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ ______.00 (UNITED STATES DOLLARS ____________ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

____

____

____

A DRAWING CERTIFICATE SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF PRESENTATION CONTAINING THE FOLLOWING STATEMENT:

“THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] (“ISSUER”), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. (“ISO”), THAT [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_______________.”

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _________ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. ___________ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY

DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE

ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE WHEN ACTUALLY RECEIVED BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

______________________________ ______________________________

[signature] [signature]

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity’s independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____
(Signature)

Print Name:__________________________________

Title: ______________________________________

Date: ______________________________________

[1] As used in this certification, a Certifying Entity’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Certifying Entity’s trading functions, such as a risk management committee, a risk officer, a Certifying Entity’s board or board committee, or a board or committee of the Certifying Entity’s parent company.

ATTACHMENT 4

ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS

CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of

____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an “appropriate person,” as defined in section(s) [ ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity’s total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an “eligible contract participant,” as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a “person who actively participates in the generation, transmission, or distribution of electric energy,” as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____
(Signature)

Print Name:___________________________________

Title: ____

Date: ____

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____

(Signature)

Print Name:________________________________

Title: ____

Date: ____

* As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: ____

Prepared by: ____

Customer/Applicant:[1] ____

I, ________________________, a duly authorized Senior Officer of ______________ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

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[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] 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 ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), 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.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years: *(Enter N/A if not applicable)*
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
   (Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
   (Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
   (Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
   (Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

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[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: ______________________________________

By: ____
(Signature)

Print Name: ____

Title: ____

Date: ____

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) -Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – -General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, ~~and~~ Net Commitment Period Compensation, and daily Forward Capacity Market charges and payments ("Daily FCM Charges") (all such ~~hourly~~ charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as “Transmission Charges”). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO’s settlement holidays, as listed on the ISO’s website from time to time.

b) *Electronic Funds Transfer (“EFT”).* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – -Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – -Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – - Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – -Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – - Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – -Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly Forward Capacity Market ~~Capacity~~ Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of ~~capacity charges, penalties~~ Capacity Performance Payments and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) -*Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) -*Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – –Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – –Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	**Corrected Data Must be Submitted By**
Adjustments to Monthly Regional Network Load Submissions	20th day of the fourth (4th) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 – -PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 – -Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the “Invoice Date”) so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two

Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4

(for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 – -ISO Payment of Remittance Advice Amounts. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by 11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel.

Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a "Congestion Shortfall"), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an "Unsecured Municipal Market Participant") and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the "Default Period"), pro rata based on the ISO

Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Default Amount"). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an

Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its “Financial Assurance Obligations” under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable

Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the

Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its “Transmission Obligations” under the ISO New England Financial Assurance Policy all times during that calendar year.

h) *Reduction of Payments and Increases in Transmission Charges for Other Covered Entities*.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the “Unsecured Transmission Default Amount”) for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the “Uncovered Transmission Default Amount”). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period’s Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) *Order of Settlement.*

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any 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 (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section 3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – <u>Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund</u>. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 <u>Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.</u>

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -<u>Payment Default Shortfall Fund Account.</u> Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -<u>Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures.</u> Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -<u>Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount.</u> Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – <u>ISO Review of Requested Billing Adjustment</u>.

Section 6.3.1 – <u>Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment</u>. A Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – <u>Notice of ISO Review of Requested Billing Adjustment</u>. Within three Business Days of the receipt ISO Participant Support and Solutions by of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – <u>ISO Review of Requested Billing Adjustments.</u> The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – <u>Comment Period.</u> Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – <u>ISO Action on Requested Billing Adjustment</u>. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The

ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the

Dispute Representative who are entitled to receive Confidential Information. Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer. The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment _________________

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to ________________________ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment ______ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
    a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
    b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
    c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
    d. The Recipient acknowledges that any violation o~~0~~f this Agreement may subject the Recipient to civil actions for violation thereof.
    e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _________________________	By:_________________________
Dated:________________________	Dated:________________________

III.3 Accounting And Billing

III.3.1 Introduction.

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

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

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

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

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

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

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

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

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this

calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

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

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

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

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

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

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load

Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

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

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

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

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

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

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

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy

quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

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

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

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

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

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

III.3.6.2 Eligible Data.

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

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

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

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

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

III.3.7 Eligibility for Billing Adjustments.

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

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

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

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

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

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

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic De-List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource’s capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

   (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

   (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

   (i) that interface's approved capacity transfer limit (net of tie benefits), or;

   (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $12.400/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.468/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply).~~ Prior to applying the annual adjustment for the Capacity Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.~~ The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply

Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the

Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23, 2023/24 and 2024/25 Capacity Commitment Period, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23, 2023/24 and 2024/25 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions. A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2025.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section

III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource’s location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section

III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

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 Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the 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) of the Capacity Acquiring Resource during the month 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) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Obligation Month.

(j) A resource that is not expected to achieve FCM Commercial Operation prior to the end of a given Obligation Month in accordance with posted schedules may not submit a transaction as a Capacity Acquiring Resource for that month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. 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 daily settlements 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~~ first Business Day ~~after the end~~ of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Eligibility.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.13.5.3.2.1. Timing.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.13.5.3.2.2. Application.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.5.4 Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

III.13.5.4.1 Timing of Submission.

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

III.13.5.4.2 Components of an Annual Reconfiguration Transaction.

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;

(3) the resource identification number of the Capacity Acquiring Resource, and;

3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource's maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource's maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are settled on a daily ~~monthly~~ basis during the applicable Capacity Commitment Period. The total of the daily ~~monthly~~ payment amounts for the month is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.13.6.1.1.1. Energy Market Offer Requirements.

(a) 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:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a)(i) 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.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

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 potential referral under Section III.A.19.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

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

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

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(i) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;

(ii) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;

(iii) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

In all cases an Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(i) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(ii) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

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 (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.13.6.1.4. [Reserved.]

III.13.6.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.13.6.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.13.6.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

> (i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.

III.13.6.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Resource or Seasonal Peak Demand Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming FCM Commercial Operation as described in Section III.13.3.8, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new

Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Resources and Seasonal Peak Demand Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.13.6.1.5.4 and III.13.6.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.13.6.1.5.5 and the ISO New England Manuals.

III.13.6.1.5.4. On-Peak Demand Resource and Seasonal Peak Demand Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Resource and Seasonal Peak Demand Resource in every Capacity Commitment Period during which the On-Peak Demand Resource or Seasonal Peak Demand Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values will be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Resources consisting of Energy Efficiency measures, the ISO will calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Resources and Seasonal Peak Demand Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. (For Demand Capacity Resources, summer months are April through November; all other months are winter months.) Such an audit shall not satisfy the Passive DR Audit requirement.

III.13.6.1.5.5. Additional Demand Capacity Resource Audits.
The ISO may perform additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO will establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.

Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.13.6.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

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

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not 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. [Reserved.]

III.13.6.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the

Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.13.6.1.5.5 and the ISO New England Manuals; and

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.3. Exporting Resources.

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

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource or a Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1~~, as adjusted to account for peak energy rents as described in Section III.13.7.1.2~~.

III.13.7.1.1. ~~Monthly~~ Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period~~ based on the following amounts:~~. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(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 and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the

Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six 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.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

~~**III.13.7.1.2 Peak Energy Rents.**~~

~~For Capacity Commitment Periods beginning prior to June 1, 2019, Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve FCM Commercial Operation, shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.~~

~~**III.13.7.1.2.1 Hourly PER Calculations**.~~

~~(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with one of the following formulas, which include scaling adjustments for system load and availability:~~

~~For hours within the period beginning September 30, 2016 through May 31, 2018:~~

~~Hourly PER($/kW) = [(LMP - Adjusted Hourly PER Strike Price) * [Scaling Factor] * [Availability Factor]~~

~~Where:~~

~~Adjusted Hourly PER Strike Price = Strike Price + Hourly PER Adjustment~~

~~Hourly PER Adjustment = average of Five-Minute PER Strike Price Adjustment values~~

~~Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserve clearing price - $500/MWh, 0)+ MAX (Ten-Minute Non-Spinning Reserve clearing price – Thirty-Minute Operating Reserve clearing price - $850/MWh, 0).~~

~~Strike Price = as defined below~~

~~Scaling Factor = as defined below~~

~~Availability Factor = as defined below~~

~~For all other hours:~~

~~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 Capacity Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.~~

~~Availability Factor = 0.95.~~

~~(b) PER Proxy Unit characteristics shall be as follows:~~

~~(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of the following, as determined on a daily basis: 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 AGT-CG (Non-G) hub;~~

~~(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;~~

~~(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.~~

~~III.13.7.1.2.2. Monthly PER Application.~~

~~The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or~~

~~greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.~~

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows ~~(for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments)~~.

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - 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]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition. For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in

Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in

Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), ~~less PER adjustments for resources in the zone as defined in Section III.13.7.1.2,~~ and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. ~~A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.~~ A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation ~~as of the end~~ on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.~~:~~

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all

Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections

IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.
The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity ~~Load~~ Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

> Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (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) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.
>
> Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.
>
> Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

> Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in

which the resource originally was awarded a Capacity Supply Obligation (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) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in ~~the~~ all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by ~~Zonal~~ Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation. The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation 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 Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation 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 for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's ~~annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period~~ daily Coincident Peak Contributions, to the sum of all load serving entities' ~~annual coincident contributions to the system-wide annual peak load~~ daily Coincident Peak Contributions in that Capacity Zone ~~from the calendar year prior to the start of the Capacity Commitment Period~~.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.
The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the

results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone~~, as adjusted for PER~~.

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

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated.

Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **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.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) 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 ~~most recent~~ seasonal claimed capability of the ownership entitlements in such unit at the time of qualification, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. 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
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located, and; (ii) the MW quantity of the specifically allocated CTRs. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.5. 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 charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

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COST-OF-SERVICE AGREEMENT

This COST-OF-SERVICE AGREEMENT (“Agreement”) is made as of the __ day of ______, 20__, among__________________________ (“Owner”), a _________{fill in type of legal entity}, __________________________ (“Lead Participant”), a _________{fill in type of legal entity}, acting as agent for Owner, and ISO NEW ENGLAND INC., a Delaware non-stock corporation (“ISO”).

RECITALS

A. Owner is the owner of _____ ________ (Asset ID No. ___), a __________MW electrical generating station together with appurtenant facilities and structures,, located at ___________________(the “Resource”). {If the station is comprised of more than one unit, describe all units at the station, including their MW and Asset IDs, and then define the units that are subject to this Agreement as “Resources”}

B. [Owner is [the direct wholly-owned subsidiary of /affiliate of /unaffiliated with the] {specify relationship between Owner and Lead Participant} Lead Participant, [which is a Market Participant/both of which are Participants in the New England Markets.] Owner operates the Resource in accordance with the ISO New England Filed Documents and the ISO New England System Rules. Lead Participant administers the Resource in accordance with the ISO New England Filed Documents and the ISO New England System Rules and causes energy, capacity and ancillary services from the Resource to be offered for sale into the New England Markets on behalf of Owner.

C. ISO is the Regional Transmission Organization for New England and is responsible for the operation of the New England Control Area to ensure short-term reliability and the administration of the New England Markets.

D. [Owner / Lead Participant] submitted a [Permanent De-list Bid / Non-Price Retirement Request] for the Forward Capacity Auction for the Commitment Period starting June 1, ______.

E. ISO concluded that the Resource[s] will be needed for reliability purposes during the Term and expects the Resource may be required to run out-of-economic merit order to relieve transmission constraints; and as a result [rejected the Permanent De-list Bid / did not accept the Non-Price Retirement Request].

F. The Parties have agreed (i) that Owner shall cause an FPA Section 205 proceeding to be initiated to establish the Annual Fixed Revenue Requirement and (ii) to enter into this Agreement for supplying energy, ancillary services and capacity from the Resource[s] into the New England Markets and thereby (x) set the rate by which Owner shall receive its fixed costs for the Resource[s] from Participants and (y) govern how the Lead Participant shall cause bids to be made such that Owner receives from the Participants its variable costs for such supply.

NOW THEREFORE, in consideration of the agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound by this Agreement as of the Effective Date, the Parties covenant and agree as follows:

ARTICLE 1
DEFINITIONS AND RULES OF INTERPRETATION

1.1. Definitions.

Except for the terms defined below and in the attached schedules, capitalized terms shall be as defined in the Tariff, or other applicable market rules.

1.1.1. **"Additional Expenses"** shall mean costs associated with O&M Items in excess of the Fixed O&M Expenses.

1.1.2. **"Annual Fixed Revenue Requirement"** shall have the meaning set forth in Schedule 3.

1.1.3. **"Availability"** means the capability of the Resource, in whole or in part, at any given time, to produce energy, capacity, or ancillary services in accordance with Good Utility Practice, and "Available" shall be construed accordingly.

1.1.4. **"Effective Date"** shall have the meaning set forth in Section 2.1.

1.1.5. **"Fixed O&M Expenses"** shall have the meaning set forth in Schedule 3.

1.1.6. **"Force Majeure Event"** means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, any order, regulation or restriction imposed by a Governmental Authority, or any other cause beyond a Party's control.

1.1.7. **"Forced Outage"** means any outage of the Resource (other than a Planned Outage) that (i) is taken consistent with Good Utility Practice and applicable NERC criteria and (ii) fully or partially curtails the Resource's ability to supply energy, capacity and/or ancillary services.

1.1.8. **"FPA"** means the Federal Power Act.

1.1.9. **"Governmental Authority"** means the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

1.1.10. **“Law”** means any law, treaty, code, rule, regulation, or order or determination of an arbitrator, court or other Governmental Authority, or any license, permit, certificate, authorization, qualification, or approval granted by a Governmental Authority to the extent binding on a Party or any of its property.

1.1.11. **“Month”** means the period beginning at 12:00 a.m. on the first day of the calendar month and ending at 12:00 a.m. of the first day of the next succeeding calendar month.

1.1.12. **“Monthly Reports”** shall have the meaning set forth in Section 4.4.4.

1.1.13. **“Monthly Settlement”** means the monthly settlement process set forth in the ISO New England Manuals.

1.1.14. **“Notice of Additional Expenses”** shall have the meaning set forth in Section 7.1.2(e).

1.1.15. **“Notice of Forced Outage”** shall have the meaning set forth in Section 7.1.2(b).

1.1.16**. “Notice of Shut-down”** shall have the meaning set forth in Section 7.1.2(c).

1.1.17. **“O&M Expenses”** see “Fixed O&M Expenses”

1.1.18. **“O&M Items”** means fixed O&M costs of repairs of the Resource and replacements of any part of the Resource to correct or avoid any impairment of the capability of the Resource to supply energy, capacity and/or ancillary services, which Owner expenses during the same calendar year in which it is performed, in accordance with Owner’s accounting practices.

1.1.19. **“Owner”** shall have the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, its assignee and/or designee.

1.1.20. **“Party”** means either the ISO or Owner or Lead Participant as the context requires, and “Parties,” means ISO and Owner and/or Lead Participant, as the context requires.

1.1.21. **“Periodic Cost Report”** shall have the meaning set forth in Section 6.1.1.

1.1.22. **"Planned Outage,"** means a planned interruption, in whole or in part, in the electrical output of a Resource to permit Owner to perform maintenance and repair of the Resource, including O&M Items.

1.1.23. **"Resource"** shall have the meaning set forth in the Recitals.

1.1.24. **"Resource Characteristics"** shall have the meaning set forth in Section 3.4

1.1.25. **"Shut-down"** shall have the meaning set forth in Section 7.1.2(c).

1.1.26. **"Shut-down Date"** shall have the meaning set forth in Section 7.1.2(f).

1.1.27. **"Stipulated Marginal Cost"** shall have the meaning set forth in Section 3.4.

1.1.28. **"Stipulated Variable Cost"** shall have the meaning set forth in Section 3.4.

1.1.29. **"Stipulated Start-Up Cost"** shall have the meaning set forth in Section 3.4.

1.1.30. **"Stipulated No-Load Cost"** shall have the meaning set forth in Section 3.4.

1.1.31. **"Stipulated Regulation Offer"** shall have the meaning set forth in Section 3.4

1.1.32. **"Supplemental Capacity Payment"** shall have the meaning set forth in Schedule 3.

1.1.33. **"Term"** shall have the meaning set forth in Section 2.1.

1.1.34. **"Variable O&M"** shall be the amount specified in Schedule 1.

1.2. Interpretation.

In this Agreement, unless otherwise indicated or otherwise required by the context, the following rules of interpretation shall apply:

1.2.1. Reference to and the definition of any document (including this Agreement, ISO New England Filed Documents and the ISO New England System Rules) shall be deemed a reference to such document as it may be amended, supplemented, revised, or modified from time to time and any document that is a successor thereto.

1.2.2. The article and section headings, and other captions in this Agreement are for the purpose of reference only and do not limit or affect its meaning.

1.2.3. Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine or neuter gender shall include all genders.

1.2.4. Accounting terms used herein shall have the meanings given to them under generally accepted accounting principles within the United States consistently applied.

1.2.5. The term “including” when used herein shall be by the way of example only and shall not be considered in any way a limitation.

1.3. Construction.

This Agreement has been drafted by the Parties hereto and shall not be construed against any Party as the sole drafter.

ARTICLE 2
TERM

2.1. Effective Date and Term.

If ISO has not notified the Owner that the Resource is no longer needed for reliability reasons by 12:00 am on June 1 of the year preceding the Capacity Commitment Period for which [the Permanent De-List Bid was rejected / the Non-price Retirement Request was not accepted], this Agreement shall be effective at the beginning of the operating hour ending at 1:00 a.m., June 1, 200___ (the "Effective Date") and shall terminate at the end of the operating hour beginning at 11:00 p.m. as of the date of the termination of the [last] Resource as provided in Section 2.2 ("Term").

2.2. Termination.

This Agreement may be terminated as follows:

2.2.1. Once this Agreement is effective, it shall remain in effect for at least a 12-month Capacity Commitment Period. ISO shall terminate this Agreement as to [the/a] Resource effective any time after such minimum 12-month term upon one hundred twenty (120) days written notice to Owner when ISO determines that [the/a] Resource is no longer needed for system reliability. The one-hundred twenty day notice may be issued by ISO prior to the completion of the minimum 12-month term. If two or more Resources are subject to this Agreement, the Agreement may be terminated with respect to one or more individual Resources. The Agreement terminates as of the date that ISO has terminated the Agreement with respect to all of the Resources that were subject to the Agreement as of the Effective date. Owner shall provide timely notice of any such termination of this Agreement to the Commission.

2.2.2. Upon 30 days notice to the Owner, the ISO may unilaterally terminate this Agreement if, over the twelve (12) month period preceding the notice, the ISO determines that the average value over all hours in that period of the ratio of the Resource's Economic Maximum as it may be redeclared from time to time to the Capacity Supply Obligation is less than fifty percent (50%). Owner shall retain all of its existing rights to challenge the ISO's calculation under the ISO Billing Policy.

2.2.3. This Agreement may be terminated as provided in Section 7.1.2, Section 9.2 and Section 11.4.

2.2.4. Consequence of Termination or Expiration. [One of the following alternatives shall be applicable to each Resource]

[Inasmuch as the Owner submitted a Permanent De-List Bid, upon termination, the provisions of Market Rule 1, Section III.13.2.5.2.5 apply and as of the date of termination the Resource is de-listed, relieved of its Capacity Supply Obligation, and no longer receives compensation under the Agreement. In addition, the Resource is no longer eligible to participate as an Existing Resource in any reconfiguration auction, Forward Capacity Auction, or Capacity Supply Obligation Bilateral for the then current Capacity Commitment Period or subsequent periods of Capacity Commitment Periods.]

[Inasmuch as the Owner submitted a Non-Price Retirement Request, unless pursuant to Market Rule 1 Section III.13.1.2.3.1.5 the Commission has directed that the obligation to retire be removed, upon termination the provisions of Market Rule 1 Section III.13.2.5.2.5 shall apply, and, as of the date of termination, the Resource is de-listed, relieved of its Capacity Supply Obligation, and no longer receives compensation under this Agreement. In addition, upon termination of the Agreement, the interconnection rights for the Resource shall terminate and the status of the Resource will be converted to retired.]

2.3. Survival.

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement which by their nature are intended to, and shall, survive such termination.

ARTICLE 3
RIGHTS AND OBLIGATIONS

3.1. In General.

During the Term, the Resource is a listed Generating Capacity Resource with a Capacity Supply Obligation. The Owner and Lead Participant shall operate, maintain and administer the Resource in accordance with (a) this Agreement, (b) the ISO New England Filed Documents, (c) the ISO New England System Rules, and (d) Good Utility Practice, as applicable. Nothing herein shall be construed as to require the Owner or Lead Participant to take action that is contrary to Good Utility Practice.

3.2. Insurance.

Owner shall arrange for and maintain an appropriate level of liability and property insurance with respect to the Resource consistent with Good Utility Practice.

3.3. Bilateral Agreements.

The Resource will not be subject to any bilateral agreement for the sale or control of energy, capacity, or ancillary services from the Resource, unless the Owner or Lead Participant, as applicable, provides the ISO with a written copy of the proposed agreement at least 30 days in advance. If, upon the Effective Date, the Owner is not the registered Owner in ISO's Customer and Asset Management System (CAMS) for the full output of the Resource, the Owner shall provide the ISO with a written copy of any agreement between the Owner and the Registered Owner within seven days.

3.4. Supply Offers.

For each day, the Lead Participant shall offer for sale energy and ancillary services into the New England Markets from the Resource based on the characteristics and operating parameters specified in Schedule 2 (the "Resource Characteristics") and with Supply Offers equal to the Stipulated Variable Costs as provided below. Lead Participant shall use commercially reasonable efforts to cause the submittal of Supply Offers for hourly values of Economic Minimum and Economic Maximum that are consistent with ambient air forecasts and /or environmental permit parameters. [Lead Participant also shall offer Regulation into the New England Markets from the Resource based on the Resource Characteristics using only Stipulated Regulation Offers as defined below.]

3.4.1. The Stipulated Variable Costs shall be self-adjusting formulary rates accepted by the Commission pursuant to the FPA Section 205 proceeding initiated by Owner and updated daily or at the most frequent time interval permitted under the ISO New England System Rules. Stipulated Variable Costs shall be determined according to the definitions below using parameter values from Schedule 1.

Stipulated Marginal Cost ("SMC") per MWh	=	(Fuel + O&M + Other)

Where:

Fuel	=	Heat Rate, MMBTU/MWh x (Fuel Index Price, $MMBTU, +Approved Fuel Variable Transportation Service Charges, $MMBTU) + Fuel Cost Other per MWh]
O&M	=	Variable O&M for energy production per MWh as specified in Schedule 1
Other	=	(SO2 Allowance Adder + NOx Allowance Adder + CO2 Allowance Adder + Other Allowance Adder + Operating Permit Adder)

Stipulated Variable Costs	=	Stipulated Marginal Cost + Stipulated Start-Up Cost + Stipulated No-Load Cost

Where:

Stipulated Start-Up Cost per Start	=	(Start-Up Fuel Use x Fuel Index Price, $/MMBTU) + Start-Up O&M + Start-Up Other (as specified in Schedule 1)
Stipulated No-Load Cost per Service	=	(No Load Fuel Use, MMBTU x Fuel Index Price, $/MMBTU) + Fuel Cost Ancillaries + Hour No Load O&M + No-Load Other (as specified in Schedule 1)

3.4.1.1 The "Fuel Index Price" shall mean the current daily price, using the third party data as specified on Schedule 1, applicable to the delivery point specified on Schedule 1.

3.4.1.2 ["Stipulated Regulation Offer" shall mean the actual offer for providing Regulation from the Resource, which shall not exceed $[100] or the cap specified in Market Rule 1, as may be amended from time to time. {Note: Owner/Lead Participant to discuss with Market Monitoring if Resource has supplied regulation service}].

3.5. Self-Scheduling.

As long as a fuel limitation does not result, and subject to the ISO New England System Rules, the ISO New England Operating Documents and the compensation provisions of Article 4, the Lead Participant may request to self-schedule the Resource for operational and maintenance considerations, including testing, and fuel management purposes . ISO System Operations may accept or not accept the self-schedule in its sole discretion

ARTICLE 4
COMPENSATION AND SETTLEMENT

4.1. In General.

The Owner is subject to charges and credits for services in the New England Markets, including the Supplemental Capacity Payment, in accordance with the ISO New England System Rules and the ISO New England Administrative Procedures, with settlement taking place in the normal weekly and monthly settlement processes as they may be amended from time to time. If an entity other than the Owner has been registered as the Owner in the ISO's Customer and Asset Registration System ("Registered Owner"), then the Supplemental Capacity Payment shall be settled through the account of the Registered Owner unless the Owner has a settlement account with the ISO and, after consent by ISO, the Owner, Registered Owner and Lead Participant provide written authorization to settle the Supplemental Capacity Payment through the Owner's Settlement Account. The Owner, Registered Owner and Lead Participant must comply with all ISO requirements for customer and asset registration.

4.2. Variable Cost Recovery.

In order to provide for recovery of variable costs, the Supply Offers applicable to the Resource as determined in accordance with Section 3.4. shall be included in the calculation of Net Commitment Period Compensation ("NCPC") and the Revenue Credit as defined below. All NCPC shall be paid in accordance with applicable ISO settlement procedures.

4.3. Fixed-Cost Recovery.

Owner shall be entitled to a Supplemental Capacity Payment for the Resource for each Month, calculated in accordance with Schedule 3, which ISO shall cause to be paid by Participants through the monthly settlement process for the New England Markets. The Annual Fixed Revenue Requirement shall be as determined by the Commission pursuant to an FPA Section 205 proceeding initiated by Owner.

4.4. Revenue Credit.

4.4.1. In General. All revenues related to the Resource less the variable costs of producing those revenues ("Revenue Credit") shall reduce the Supplemental Capacity Payment in accordance with the formulas in Schedule 3.

4.4.2. FCA Payments. The Revenue Credit shall include the FCA Payment as it has been adjusted for Peak Energy Rent and Availability Penalties in the normal FCA settlement. The adjusted amount is allowed to be negative in the calculation of the Revenue Credit and to increase the Supplemental Capacity Payment (when that part of the calculation is viewed in isolation). Provided, however, any Availability Credits earned pursuant to the provisions of Market Rule 1, Section III.13.7.2.7.1.4 shall be ignored for calculating the Revenue Credit and shall inure to the benefit of the Owner, subject to the maximum earnings provision of Schedule 3, Part 1.

4.4.3. Revenues Received in the New England Markets. All revenues related to the Resource earned in the New England Markets settled by ISO (in addition to the revenues earned in the Forward Capacity Market above), less the Stipulated Variable Cost of producing those revenues as represented by the Supply Offers, shall be included in the calculation of the Revenue Credit. For self-scheduled hours, inframarginal revenue shall not be reduced for Stipulated Variable Costs in excess of hourly revenue. Monthly inframarginal revenue is the sum of all daily positive inframarginal revenue values. If the revenues related to the Resource are not paid on a Resource specific basis, the ISO shall allocate such revenues to the Resources that are subject to this Agreement.

4.4.4. Other Revenues. Any revenues related to the Resource that have not been settled by ISO (including from bilateral agreements, emission credits, release of firm transportation arrangements, sale of surplus equipment etc.), less any incremental costs directly related to securing additional revenue that are not already accounted for in the Annual Fixed Revenue Requirement or Stipulated Variable Costs, will be included in the Revenue Credit. These incremental costs may not be greater than the incremental revenues on a case-by-case basis. The Owner and Lead Participant shall report all such other revenues, or the absence thereof, to ISO in a monthly report (the “Monthly Report”).

ARTICLE 5
MARKET MONITORING

5.1. Mitigation.

Although this Agreement provides for Supply Offers that do not exceed thresholds identified in Appendix A, Market Rule 1, nothing herein shall preclude the ISO from otherwise applying any provision of Appendix A to Market Rule 1 to Owner or Lead Participant, any Affiliate of Owner or Lead Participant, the Resource, or any other resources of Owner or Lead Participant or any Affiliate of Owner or Lead Participant, including mitigation of Supply Offers for Resources covered by this Agreement to the applicable Stipulated Variable Cost as defined in Section 3.4.

5.2. Adjustment.

After consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost are subject to adjustment by ISO Market Monitoring to Stipulated Variable Cost.

5.3. Dual Fuel Resources [If dual fuel].

The Lead Participant is required to submit Supply Offers reflecting the fuel to be used. If the Lead Participant is to submit Supply Offers based on the higher cost fuel, it must advise ISO Market Monitory as soon as practicable in advance of submitting such an offer and provide a written explanation as to the cause, Availability implications and expected duration.

ARTICLE 6
REPORTING

6.1. Variable Cost and Resource Characteristic Reporting.

6.1.1. Owner shall update the components of Stipulated Variable Costs that are not publicly available as they may change from time to time on a timely basis, along with supporting information as requested, in a format approved by ISO and consistent with the formulas provided in Section 3.4 and Schedule 1 (the "Periodic Cost Report"). If Owner fails to provide updated information on a timely basis, Supply Offers may be adjusted to Stipulated Variable Costs based on the information on file. ISO will give Owner 30 days prior written notice of any change in the form of the Periodic Cost Report.

6.1.2. The Resource Characteristics applicable to the Resource during the Term are set forth in Schedule 2 hereto. Owner shall provide ISO with updated Resource Characteristics set forth on a revised Schedule 2 immediately upon any change of those Resource Characteristics. If ISO does not agree to the revised Schedule, the Schedule in effect shall remain in effect during the Term pending alternative dispute resolution in accordance with Appendix D to Market Rule 1.

6.2. Books and Records; Audit Rights.

ISO shall have the right, at any time upon reasonable notice, to examine at reasonable times the books and records of Owner and Lead Participant to the extent necessary to audit and verify the accuracy of all reports, statements, invoices, charges, or computations pursuant to this Agreement. The Parties acknowledge and agree that ISO may perform audits of the Monthly Reports and the Periodic Cost Reports as well as a final audit of all expenses incurred under this Agreement upon completion of the Term. All information provided during the course of such an examination shall be treated as confidential information under applicable ISO Protocols.

ARTICLE 7
RESOURCE OPERATION AND MAINTENANCE

7.1. Planned and Forced Outages.

7.1.1. Planned Outages. Owner shall be entitled to take the Resource out of operation or reduce the net capability of the Resource during Planned Outages, in accordance with the schedule for Planned Outages as established and implemented pursuant to the ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA.

7.1.2. Forced Outages.

(a) Generally. Owner shall be entitled to take the Resource out of operation or reduce the net capability of the Resource upon the occurrence of a Forced Outage.

(b) Notice of Forced Outage. In the event of a Forced Outage that is anticipated to last for more than ten (10) days, in addition to any other notification obligation arising under ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA, Owner shall promptly notify ISO Reliability Contract Services in writing of its occurrence, estimated duration, and whether Additional Expenses are expected to be required to return the Resource to service (a "Notice of Forced Outage"). Owner shall also inform ISO of the availability of any previously retired unit (the “Substitute Unit”) and the costs and time required to bring the Substitute Unit back into service and to retire the Resource on Forced Outage.

(c) Notice of Shut-down. As soon as reasonably practicable after the date of a Notice of Forced Outage but in no event greater than thirty (30) days from the start of such Forced Outage, either Party may, after assessing the nature, expected duration, and expected incurrence of Additional Expenses, notify the other in writing of its determination that the Resource shall, subject to the provisions of Section 7.1.2(e), be Shut-down (a "Notice of Shut-down") and if such notice applies to the entire Resource that this Agreement should be terminated.

(d) Supplemental Capacity Payment. In the event that the Resource is Shutdown, Owner shall only remain entitled to receive the Supplemental Capacity Payment based on the AFRR through the Shut-down Date; provided that with respect to a Shut-down applying only to a unit, this Agreement shall remain in full force and effect with respect to the remaining unit(s). Owner may file amendments to the AFRR with the Commission.

(e) Option to Approve Additional Expenses. With respect to a Notice of Shutdown made by Owner, if within thirty (30) days of receipt of Owner's Notice of Shut-down ISO provides written notice to Owner that it is willing to pass through for payment by the Participants in the Monthly Settlement process of the New England Markets such Additional Expenses (a "Notice of Additional Expenses") that may be required to recover from such Forced Outage, Owner agrees that it will, with reasonable dispatch, take the action requested by ISO, i.e., not Shut-down the Resource and make such Additional Expenses as paid to it by the Participants to return the Resource to service from such Forced Outage, or make such expenditures as paid to it by the Participants to bring the Substitute Unit into service and retire the Resource on Forced Outage. The Parties agree that the effectiveness of a Notice of Additional Expenses shall be immediately effective, and Owner shall be entitled to begin receiving payments from ISO pursuant thereto, as of the day following the date the Owner files a request under Section 205 of the FPA with the Commission to recover from ISO the Additional Expenses identified in the Notice of Additional Expenses. Payments will be made subject to refund pending the approval of such Additional Expenses by the Commission. The Parties further agree that Owner is obligated to use its best efforts to minimize Additional Expenses and that the amounts approved under the Notice of Additional Expenses are subject to offset by any proceeds from any and all third-party sources, including insurance proceeds, paid to Owner to return the Resource from the Forced Outage. Owner shall make a subsequent reconciliation (“true-up”) filing with the Commission and refund any payments for Additional Expenses paid to Owner that are disallowed by the Commission, or that exceed the amount actually expended by the Owner, after offsets.

(f) Shut-down Date. With respect to a Notice of Shut-down issued by ISO pursuant to Section 7.1.2(c), the “Shut-down Date” shall be that date ten (10) days after the receipt of such Notice of Shut-down by the Owner. With respect to a Notice of Shut-down issued by Owner pursuant to Section 7.1.2(c), the “Shut-down Date” shall be that date thirty (30) days after the receipt of such Notice of Shutdown by ISO unless ISO has issued a Notice of Additional Expenses in accordance with Section 7.1.2(e), in which case no Shut-down Date will have occurred with respect to such Notice of Shut-down or the Shut-down Date will be the date on which the Substitute Unit is brought back into service. As of the Shutdown Date, the interconnection rights for the Resource shall terminate and the status of the Resource will be converted to retired.

7.2. Additional and Other Expenses.

Except as provided for in Section 7.1, Owner shall (i) not be required or otherwise obligated to incur any Additional Expenses and (ii) not be required to enter into any additional agreements or incur any additional costs, including fixed-fuel costs, that Owner is not already obligated to enter into, or incur, as the case may be, that are not otherwise contemplated by, and being recovered by Owner pursuant to, the Annual Fixed Revenue Requirement.

ARTICLE 8
FORCE MAJEURE EVENTS

8.1. Notice of Force Majeure Event.

If any Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party unable to perform shall promptly notify the other Party.

8.2. Effect of Force Majeure Event.

If the Availability of the Resource is reduced by reason of a Force Majeure Event, Section 7.1.2 shall apply (i.e. a Force Majeure Event shall be deemed to create a Forced Outage). Subject to reduction by the COS Availability Penalty and to Sections 7.1.2, 9.2, and 11.4, Owner shall continue to receive the Supplemental Capacity Payment without any other reduction while the Force Majeure Event continues.

8.3. Remedial Efforts.

The Party unable to perform by reason of a Force Majeure Event shall use reasonable efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event as soon as reasonably practicable; provided that (i) no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests and (ii) subject to Sections 7.1.2 and 7.2, the Party unable to perform shall, as soon as practicable, advise the other Party of the reason for its inability to perform, the nature of any corrective action needed to resolve performance, and its efforts to remedy its inability to perform and to mitigate the consequences of its inability to perform and shall advise the other Party of when it estimates it will be able to resume performance of its obligations under this Agreement.

ARTICLE 9
REMEDIES

9.1. Damages and Other Relief.

9.1.1. Liability of ISO. ISO shall not be liable to Owner or Lead Participant for actions or omissions by ISO in performing its obligations under this Agreement, provided it has not willfully breached this Agreement or engaged in willful misconduct. To the extent Owner or Lead Participant has claims against ISO, Owner and Lead Participant may only look to the assets of ISO for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees or agents of ISO who, Owner and Lead Participant acknowledge and agree, have no personal liability for obligations of ISO by reason of their status as directors, members, officers, employees or agents of ISO.

9.1.2. Liability of Owner. Except as provided by the COS Availability Penalty, Owner and Lead Participant shall not be liable to ISO for actions or omissions by Owner or Lead Participant in performing their obligations under this Agreement, provided that Owner or Lead Participant has not willfully breached this Agreement or engaged in willful misconduct.

9.1.3. Limitation of Liability. In no event shall Owner and Lead Participant be liable to ISO or ISO be liable to Owner and Lead Participant for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Agreement.

9.1.4. Indemnification. Owner and Lead Participant shall indemnify, defend and save harmless ISO and its directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by ISO under this Agreement or the actions or omissions of Owner and Lead Participant in connection with this Agreement, except in cases of gross negligence or willful misconduct by ISO or its directors, officers, members, employees or agents.

9.2. Termination for Default.

If any Party shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, the other Party, at its option, may terminate this Agreement by giving the Party in default written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within ten (10) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages. Termination of this Agreement pursuant to this Section 9.2 shall be without prejudice to the right of any Party to collect any amounts due to it prior to the time of termination.

9.3. Waiver.

The failure to exercise any remedy or to enforce any right provided in this Agreement or applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing.

9.4. Beneficiaries.

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any Party.

ARTICLE 10
COVENANTS OF THE PARTIES

10.1. ISO represents and warrants to Owner and Lead Participant as follows:

10.1.1. ISO is a validly existing corporation with full authority to enter into this Agreement.

10.1.2. ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of ISO.

10.1.3. ISO has all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.1.4. The execution, delivery, and performance of this Agreement are within ISO's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2. Owner represents and warrants to ISO as follows:

10.2.1. Owner is a validly existing entity with full authority to enter into this Agreement.

10.2.2. Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Owner.

10.2.3. Owner has, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.2.4. The execution, delivery, and performance of this Agreement are within the Owner's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.3. Lead Participant represents and warrants to ISO as follows:

10.3.1. Lead Participant is a validly existing entity with full authority to enter into this Agreement.

10.3.2. Lead Participant has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Agent.

10.3.3. Lead Participant has, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.3.4. The execution, delivery, and performance of this Agreement are within the Lead Participants powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

ARTICLE 11
MISCELLANEOUS PROVISIONS

11.1. Assignment.

11.1.1. None of the Parties shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Article 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Parties.

11.1.2. Notwithstanding Section 11.1.1, each Party may, without the need for consent from the other Party (and without relieving itself from liability hereunder), transfer or assign this Agreement: (i) to an Affiliate, or (ii) where such transfer is incident to a merger or consolidation with, or transfer of all, or substantially all, of the assets of the transferor to another person, business entity, or political subdivision or public corporation created under the Laws governing the creation and existence of the transferor which shall as a part of such succession assume all of the obligations of the assignor or transferor under this Agreement. Provided, however, that any Party who transfers or assigns this Agreement as provided in subsections “i” or “ii” of this Section 11.1.2 shall provide timely notice to the other Party or Parties of such change, including the effective date and changes, if any, to the nominations under Section 11.2 and Exhibits A or B, as appropriate. Any Party may collaterally assign its rights in this Agreement to its lenders without the need for consent from the other Party. To the extent that any Party seeks to transfer its rights and obligations to a successor entity, such Party shall seek to assign this Agreement to such successor entity, pursuant to this Section 11.1.2.

11.1.3. Upon 60 days notice from Owner or Lead Participant, the Lead Market Participant’s role under this Agreement may terminate and then this function must be assigned by Owner to another entity fully capable of fulfilling this role consistent with the ISO New England Filed Documents and the ISO New England System Rules. The Owner, the current Lead Participant, and the successor Lead Participant must comply with all ISO requirements for Customer Asset registration. Owner is not obligated to assign the Lead Market Participant role to another entity and may assume this role, if it is qualified to do so, by notifying the ISO.

11.1.4. The Owner may designate a new Registered Owner by providing 30 days notice under the Agreement and a written copy of any agreement between the Owner and the new registered Owner. The Owner, the Registered Owner and the Lead Participant must comply with all ISO requirements for Customer and Asset registration.

11.2. Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person or by facsimile; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

OWNER AND LEAD PARTICIPANT:
NOTICES & CORRESPONDENCE
[TO COME]

ISO:
NOTICES & CORRESPONDENCE
~~Mark H. Freise, Reliability Contracts Manager~~
[Name], [Title]
ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040
~~-~~Tel: [to be provided] ~~(413) 540-4429~~ Fax: [to be provided] ~~(413) 535-4156~~

with a copy to:
[Name], [Title]
~~Theodore Paradise Senior Counsel~~
ISO New England Inc.
One Sullivan Road Holyoke, MA 01040
Tel: [to be provided] Fax: [to be provided]
~~Tel: (413) 540-4585 Fax: (413) 535-4379~~

The foregoing notice provisions may be modified by providing written notice, in accordance with ISO Protocols established from time-to-time.

11.3. Parties' Representatives.

All Parties to this Agreement shall ensure that throughout the term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party. Owner's and Lead Participants representatives shall be identified on Exhibit A. ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Party a revision to its respective Exhibit.

11.4. Effect of Invalidation, Modification, or Condition.

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition. If the Parties fail to reach agreement, then the Party whose rights and obligations have been adversely affected may, in its sole discretion, terminate this Agreement or refer the dispute for resolution under the Alternative Dispute Resolution provisions in Appendix D of Market Rule 1.

11.5. Amendments.

Any amendments or modifications of this Agreement shall be made only in writing and duly executed by all Parties to this Agreement. Such amendments or modifications shall become effective only after the Parties have received any authorizations required from the Commission. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein and to reflect any changes to the design of the New England Markets that are approved by the Commission from time to time.

11.6. Governing Law.

This Agreement shall be governed by and construed under the Laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles.

11.7. Entire Agreement.

This Agreement consists of the terms and conditions set forth herein, as well as the Appendices hereto, which are incorporated by reference herein and made a part hereof. This Agreement contains the entire agreement between the Parties and supersedes all prior negotiations, undertakings, agreements and business term sheets.

11.8. Independent Contractors.

Owner (and Lead Participant, as Owner's representative) and ISO acknowledge that as between Owner and ISO there is an independent contractor relationship, and that nothing in this Agreement shall create any joint venture, partnership, or principal/agent relationship between the Parties. Neither Owner or Lead Participant nor ISO shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

11.9. Counterparts.

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same agreement.

11.10. Confidentiality.

Confidential information identified as such by a Party and provided to the other Party pursuant to this Agreement shall be governed by the ISO New England Information Policy, subject to the following:

11.10.1. Nothing herein or therein shall limit the right of a Party to file a copy of this Agreement with the Commission, without redaction, to the extent that law, regulation, or agency order makes such filing necessary or appropriate.

11.10.2. Notwithstanding anything in this Agreement to the contrary, if during the course of an investigation or otherwise, the Commission requests that a Party (the "responding Party") provide to it information that has been designated by the other Party to be treated as confidential under this Agreement, the responding Party shall provide the requested information to the Commission or its staff within the time provided for in the request for information. The responding Party shall promptly notify the other Party upon receipt of any such request and either Party, consistent with 18 CFR § 388.112, may, but shall not be required, to request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure.

11.11. Submittal to the Commission.

The Parties acknowledge and agree that (i) the Annual Fixed Revenue Requirement and the formula for calculating Stipulated Variable Costs shall be established pursuant to an FPA Section 205 proceeding to be initiated by application of Owner provided, however, that any application for changes to the formula for calculating Stipulated Variable Costs shall be made only under Section 206; (ii) this Agreement constitutes the basis for Owner's recovery of its fixed and variable costs for operating and maintaining the Resource during the Term.

IN WITNESS WHEREOF, this Agreement has been executed as of the date first above written.

[OWNER NAME]
By:
Name:
Title:

ISO NEW ENGLAND INC.
By: Name:
Title:

[LEAD PARTICIPANT NAME]
By: Name:
Title:

EXHIBIT A

OWNER'S AND LEAD PARTICIPANT'S REPRESENTATIVES

[OWNER AND LEAD PARTICIPANT TO PROVIDE]

EXHIBIT B

ISO'S REPRESENTATIVES

~~Kevin Kirby~~[Name]

~~Vice President, Market Operations~~[Title]

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

SCHEDULE 1
INFORMATION ON MARGINAL COST

[The Lead Participant or Owner shall provide the ISO, on a timely basis in advance of the Section 205 filing prior to the commencement of the Capacity Commitment Period, with draft Schedule 1 and Schedule 2 including supporting cost and other information, as the ISO may require.]

1. The Fuel Index Price for the Resource:

a. Natural Gas – specify price index, delivery point, pipeline and Local Distribution Company (“LDC”).

b. Applicable gas contract including any transportation charges, Other Fossil fuel – specify price index, delivery type (barge, tanker, rail, truck). Applicable fuel contract, including any transportation agreements and applicable (sales) tax.

Each Fuel Index Price shall use the following data source(s), respectively, as appropriate:

[Check applicable box]

☐Energy/Petroleum Argus
☐Intercontinental Commodities Exchange (“ICE”)
☐Other (as mutually agreed)_________________

[Check applicable box]

Fuel Type	**Frequency of Data**
☐Coal_	weekly
☐Natural Gas	daily (business days)
☐No2	daily (business days)
☐No2_LS_aka_DIESEL	daily (business days)
☐No6_030	daily (business days)
☐No6_070	daily (business days)
☐No6_100	daily (business days)

☐No6_220 daily (business days)

☐No6_300 daily (business days)

☐Jet_fuel daily (business days)

☐LS_Jet_kero daily (business days)

2. Based on the following delivery point__________________________. The Heat Rate for use with the Fuel Index Price for the Resource to calculate Marginal Fuel Cost is set forth in the following table[s for each fuel type] expressed in MMBTU/MWh]. The table shows the incremental heat rate (include a minimum of four data points, ranging from zero output and including Ecomin and Ecomax values). Dual fuel units should provide this data on a fuel specific basis.

3. Provide information about any other components of the marginal fuel cost, including variable transportation and Fuel Cost Ancillaries, if any.

4. Provide information on Variable O&M for energy production, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3. (Dual fuel units should provide this data on a fuel specific basis).

5. Provide information about any other components of marginal costs, including emission allowance adders and operating permit adders, if any. (Express NOx, SO2, CO2 and any other emission rates in Lbs/MMBTU. (Dual fuel units should provide this data on a fuel specific basis).

6. Provide information about Start-Up Costs. Stipulated Start-up costs are variable costs that are incurred prior to synchronization and when operating below EcoMin, to the extent those variable costs are not recovered in the energy market or NCPC, as shown in the following table(s) for each fuel type:

a. (on a fuel specific basis): fuel input (mmBtu's);

b. O&M component for starts, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3, itemized; and,

c. "Start-Up other", itemized, if applicable

7. Provide information about No-Load Costs. No-load costs are those costs that vary in the service hours and are independent of output and are as shown in the following table(s) for each fuel type:

a. (on a fuel specific basis): input (mmBtu's);

b. No-Load O&M component for Service Hours, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3, itemized; and

c. No-Load Other, itemized, if applicable.

For example [add columns for other parameters, including CO2 emission rate as necessary]:

SAMPLE TABLE

Fuel Type

____

Data Source: Daily Price Survey midpoint

Delivery Point: [______________

Net Output (may have up to 10 segments)	Marginal Heat Rate (mmBTU/MWh)	Fuel Ancillaries ($/kWh)	Variable O&M ($/MWh)	NOx Emission Rate (lbs/MWh)*	SO_2 Emission Rate (lbs/MWh)**
0 MW to EcoMin of e.g., 30 MW	10.200	N/A	$1.84	2.55	0.31
31 MW - 60 MW	10.750	N/A	$1.84	2.69	0.32
61 MW - 90 MW	11.600	N/A	$1.84	2.90	0.35
90 MW – Eco Max e.g., 107 MW	12.300	N/A	$1.84	3.08	0.37

Start-Up	Fuel (mmBTU)	Start-Up Fuel Ancillaries ($/mmBTU)	Start-Up O&M ($/start)	NOx Emission Rate (lbs/start)*	SO_2 Emission Rate (lbs/start)**
Cold	400	N/A	$0	100	12
Intermediate	350	N/A	$0	88	11
Hot	300	N/A	$0	75	9

No Load Conditions	No Load Fuel (mmBTU/hr)	Start-Up Fuel Ancillaries ($/mmBTU)	No Load NOx Emission Rate (lb/hr)*	No Load SO_2 Emission Rate (lb/hr)*
	81	N/A	20.25	2.43

- As referenced in Section 3.4, "Supply Offers," the NOx Allowance Adder shall be calculated as: the appropriate NOx Emission Rate from the table above times the daily quoted price of average trades in $/ton as posted by Evolution Markets, LLC on http://www.evomarkets.com, divided by 2000 (lbs/ton).

- As referenced in Section 3.4, "Supply Offers," the SO2 Allowance Adder shall be calculated as: the appropriate SO2 Emission Rate from the table above times the daily quoted price of average trades in $/ton as posted by Evolution Markets, LLC on http://www.evomarkets.com, divided by 2000 (lbs/ton).

- For use in calculating the Resource's Stipulated Bid Costs, the NOx emission rate shall only be included for bids submitted for operation during the NOx season (May through September of each calendar year).

* NOx Emission Rate = [e.g., 0.25] lb/mmbtu on natural gas

** SO2 Emission Rate = [e.g., 0.03] lb/mmbtu on natural gas

SCHEDULE 2
RESOURCE CHARACTERISTICS

[RESOURCE NAME]

(NOTE: for combine cycles, provide the following for each mode of operation)

EcoMin: ___________

Qualified Capacity* ___________ MW (Winter) ___________MW (Summer)

EcoMax (emergency) (as applicable gas/oil: ___________MW

Ramp Rate (Normal): ___________MW/Minute

Ramp Rate (emergency): ___________MW/Minute

Minimum Run Time: ___________hours

Minimum Shutdown Time: ___________hours

Notification Time (Cold):** ___________hours

Start-Up Time (Cold Conditions)***: ___________hours

Notification Time (Warm)** ___________hours

Start-Up Time (Warm Conditions)***: ___________hours

Notification Time (Hot)** ___________hours

Start-Up Time (Hot Conditions) ___________hours

Start-Up Profile ___________(MWh)__________(MMBTU)

Shut-Down Profile ___________(MWh)__________(MMBTU)

*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 process (Market Rule III.1.3.2) including challenge provisions as appropriate.

** “Notification Time” is defined consistent with eMarket specifications as the time required from an ISO-issued start order to the synchronization of the Resource.

*** “Start Up Time” is defined consistent with eMarket specifications as the time required from synchronization of the Resource to the time the Resource reaches its EcoMin level of output and available for ISO dispatch.

For each day, Lead Participant shall use commercially reasonable efforts to cause the submittal of Supply Offers for hourly values of EcoMax and EcoMin that are consistent with ambient atmospheric conditions and equipment operating conditions.

SCHEDULE 3

SUPPLEMENTAL CAPACITY PAYMENT

For each Obligation Month during the Term, a Supplemental Capacity Payment shall be calculated for the Resource[s] as set forth below. The Supplemental Capacity Payment shall be charged to Regional Network Load in the affected Reliability Region.

Section III.13 references are to Market Rule 1, Section III.13 – Forward Capacity Market.

The Annual Fixed Revenue Requirement (AFRR) for the [generating station / Resource] is $___________.

The Annual Fixed O&M Expenses for the [generating station / Resource] is $___________.

The AFRR is the cost-of-service for the [generating station / Resource], including fixed operation and maintenance expenses, depreciation, amortization, taxes and return, as accepted by the Commission. The Annual Fixed O&M Expenses is the fixed operating & maintenance expense component of the AFRR. Where the AFRR and the Annual Fixed O&M Requirement have been determined for a generating station that is composed of two or more Resources, each shall be allocated to the Resources pro-rata according to their Capacity Supply Obligations as of the Effective Date. [list the allocated amounts below.]

(Part 1)

Supplemental Capacity Payment =

Plus: Maximum Monthly Fixed Cost Payment

Less: Total COS Availability Penalties for the Obligation Month

Less: Revenue Credit for the Obligation Month

Providing that for any given Capacity Commitment Period the monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the AFRR (subject to the additional provisions of Part 5 if applicable).

In the event that the Supplemental Capacity Payment would otherwise be less than zero in any Obligation Month, the Supplemental Capacity Payment for that Obligation Month shall be zero and any unapplied COS Availability Penalty or Revenue Credit shall roll-forward for crediting in a future Obligation Month.

For the last Obligation Month of the Term, the ISO shall charge the Owner for any unapplied roll-forward amount and shall refund that amount to Regional Network Load (subject to the additional provisions of Part 5 below if applicable).

(Part 2)

Maximum Monthly Fixed Cost Payment = AFFR / 12

COS Price = Maximum Monthly Fixed Cost Payment / Capacity Supply Obligation

The Total COS Availability Penalty for the Obligation Month equals the sum of the COS Availability Penalties for each Shortage Event that has been defined and recognized in accordance with Sections III.13.7.1.1.1 through III.13.7.1.1.4. The COS Availability Penalty for each Shortage Event shall be determined in accordance with the provisions of Section III.13.7.2.7.1.2, except that it shall be based on the COS Price instead of the Capacity Clearing Price and the Annual Fixed Revenue Requirement instead of the Resource's Annualized FCA Payment. The per day and per month COS availability penalties assessed shall be subject to the caps set forth in Section III.13.7.2.7.1.3, except that the caps shall be based on the Annual Fixed Revenue Requirement rather than the Resource's Annualized FCA Payment. The sum of Total COS Availability Penalties for each Capacity Commitment Period shall not exceed the Annual Fixed Revenue Requirement.

(Part 4)

The purpose of the Revenue Credit is to recognize that the Resource has earned revenues from sources other than this Supplemental Capacity Payment. The Supplemental Capacity Payment is reduced accordingly so that the Resource receives a total payment for its capacity during the Commitment Period equal to its Annual Fixed Revenue Requirement reduced for any COS Availability Penalties.

Revenue Credit for the Obligation Month =

Plus: FCA Payment for the Obligation Month

~~Less: PER Adjustment for the Obligation Month~~

Less: Availability Penalty for the Obligation Month

Plus: All other revenues related to the Resource (i.e. all revenues except for revenues from the New England Forward Capacity Market) that are in excess of Stipulated Offer Costs. Provided, however, any Availability Credits earned according to the provisions of

Section III.13.7.2.7.1.4 shall be ignored for calculating this Revenue Credit and shall inure to the benefit of the Owner subject to the provisions of Part 1.

Where the FCA Payment~~, PER Adjustment~~ and Availability Penalty for the Obligation Month are the amounts calculated in the normal monthly settlement based on the Capacity Clearing Price for the Capacity Zone and the provisions of Section III.13.7.

(Part 5)

If this Agreement terminates other than at the end of a Capacity Commitment Period:

5.1 The ISO shall credit the Resource for Availability Penalties and COS Availability Penalties during that Capacity Commitment Period that are in excess of the pro-rated Annualized FCA Payment and AFRR respectively. The ISO shall charge the appropriate Market Participants defined in Section III.13.7.3 and Regional Network Load in the Reliability Region according to which entities had received the benefit of these excess Availability Penalties and COS Availability Penalties.

5.2 The monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the prorated AFRR.

(Part 6)

While the roll-forward provisions of Part 1 provide that the Supplemental Capacity Payment cannot result in a monthly charge to the Resource because of a Supplemental Capacity Payment that calculates to a negative amount, nothing in this Agreement provides that the sum of all charges and credits for the Resource cannot result in a net amount owed to the ISO for any Obligation/Operating Month.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

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

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

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

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

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

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

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

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

AGC is automatic generation control.

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

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

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

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

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

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.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

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

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

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

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

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

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

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

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

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

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

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

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

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

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

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

Bankruptcy Code is the United States Bankruptcy Code.

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

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

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

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

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 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 Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

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.

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 established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

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).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

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

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

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

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

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

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

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

Capacity 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 as described in Section III.13.7.5.2 of Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

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

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

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

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

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

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

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

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

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

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 Capacity Commitment Period, 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. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

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

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

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

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

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

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

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

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

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

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

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

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

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

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

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

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

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

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

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

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

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

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

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

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

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

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

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

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

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

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

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.

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

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

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

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

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

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

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

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

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

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

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

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

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction 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 Demand Reduction 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 Demand Reduction Offer Block-Hours.

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

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

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

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

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

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

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

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

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

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or

Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

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

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

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

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

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

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a

Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, 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 Operating Procedures and Manuals.

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

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

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

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

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

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

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

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

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

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

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

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

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

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

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

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

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

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

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

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

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

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

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

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

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

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

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

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

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

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

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

EMS is energy management system.

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

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

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

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

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

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

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

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

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

Energy Offer Floor is negative $150/MWh.

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

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

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

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

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

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

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process 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 Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset 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. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

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.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant 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 a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (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.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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 Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset 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 Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of 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.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO’s technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization’s activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization’s equity securities; or (b) has directly contributed 10% or more of an organization’s capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

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 Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement 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 described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 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 Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

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 Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

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 officer.

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.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

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).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart 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 Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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 Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

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.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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ATTACHMENT 6 - MINIMUM CRITERIA FOR MARKET PARTICIPATION INFORMATION DISCLOSURE FORM

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

The purpose of the ISO New England Financial Assurance Policy is (i) to establish minimum criteria for participation in the New England Markets; (ii) to establish a financial assurance policy for Market Participants and Non-Market Participant Transmission Customers that includes commercially reasonable credit review procedures to assess the financial ability of an Applicant, a Market Participant or a Non-Market Participant Transmission Customer to pay for service transactions under the Tariff and to pay its share of the ISO expenses, including amounts under Section IV of the Tariff, and including any applicable Participant Expenses; (iii) to set forth the requirements for alternative forms of security that will be deemed acceptable to the ISO and consistent with commercial practices established by the Uniform Commercial Code that protect the ISO and the Market Participants against the risk of non-payment by other, defaulting Market Participants or by Non-Market Participant Transmission Customers; (iv) to set forth the conditions under which the ISO will conduct business in a nondiscriminatory way so as to avoid the possibility of failure of payment for services rendered under the Tariff; and (v) to collect amounts past due, to collect amounts payable upon billing adjustments, to make up shortfalls in payments, to suspend Market Participants and Non-Market Participant Transmission Customers that fail to comply with the terms of the ISO New England Financial Assurance Policy, to terminate the membership of defaulting Market Participants and to terminate service to defaulting Non-Market Participant Transmission Customers.

I. GROUPS REGARDED AS SINGLE MARKET PARTICIPANTS

In the case of a group of Entities that are treated as a single Market Participant pursuant to Section 4.1 of the Second Restated NEPOOL Agreement (the "RNA"), the group members shall be deemed to have elected to be jointly and severally liable for all debts to Market Participants, PTOs, Non-Market Participant Transmission Customers, NEPOOL and the ISO of any of the group members. For the purposes of the ISO New England Financial Assurance Policy, the term "Market Participant" shall, in the case of a group of members that are treated as a single Market Participant pursuant to Section 4.1 of the RNA, be deemed to refer to the group of members as a whole, and any financial assurance provided under the ISO New England Financial Assurance Policy will be credited to the account of the group member with the customer identification at the ISO.

II. MARKET PARTICIPANTS' REVIEW AND CREDIT LIMITS

Solely for purposes of the ISO New England Financial Assurance Policy: a "Municipal Market Participant" is any Market Participant that is either (a) a Publicly Owned Entity except for an electric cooperative or an organization including one or more electric cooperatives as used in Section 1 of the RNA or (b) a municipality, an agency thereof, a body politic or a public corporation (i) that is created under the authority of any state or province that is adjacent to one of the New England states, (ii) that is authorized to own, lease and operate electric generation, transmission or distribution facilities and (iii) that has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee. Market Participants that are not Municipal Market Participants are referred to as "Non-Municipal Market Participants."

A. Minimum Criteria for Market Participation

Any entity participating or seeking to participate in the New England Markets shall comply with the requirements of this Section II.A. For purposes of this Section II.A, the term "customer" shall refer to both Market Participants and Non-Market Participant Transmission Customers and the word "applicant" shall refer to both applicants for Market Participant status and applicants for transmission service from the ISO.

1. Information Disclosure

(a) Each customer and applicant, on an annual basis (by April 30 each year) shall submit a completed information form in the form of (with only minor, non-material changes) and with the information required by Attachment 6 to the ISO New England Financial Assurance Policy. Customer or applicant shall not be required to disclose information required by Attachment 6 if such disclosure is prohibited by law; provided, however, if the disclosure of any information required by Attachment 6 is prohibited by law, then customer or applicant shall use reasonable efforts to obtain permission to make such disclosure. This information shall be treated as Confidential Information, but its disclosure pursuant to subsection (b) below is expressly permitted in accordance with the terms of the ISO New England Information Policy. Customers and applicants may satisfy the requirements above by providing the ISO with filings made to the Securities and Exchange Commission or other similar regulatory agencies that include substantially similar information to that required above, provided, however, that the customer or applicant must clearly indicate where the specific information is located in those filings. An applicant that fails to provide this information will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this information by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the information to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) The ISO will review the information provided pursuant to subsection (a) above, and will also review whether the customer or applicant or any of the Principals of the customer or applicant are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. If, after review of the information provided pursuant to subsection (a) above or any other information disclosed pursuant to this Section II, the ISO in its sole discretion requires additional information to make its analysis under this subsection (b), the ISO may require additional information from the customer or applicant. If, based on these reviews, the ISO determines that the commencement or continued participation of such customer or applicant in the New England Markets may present an unreasonable risk to those markets or its Market Participants, the Chief Financial Officer of the ISO shall promptly forward to the Participants Committee or its delegate, for its input, such concerns, together with such background materials deemed by the ISO to be necessary for the Participants Committee or its delegate to develop an informed opinion with respect to the identified concerns, including any measures that the ISO may recommend imposing as a condition to the commencement or continued participation in the markets by such customer or applicant (including suspension) or the ISO's recommendation to prohibit or terminate participation by the customer or applicant in the New England Markets. The ISO shall consider the input of the Participants Committee or its delegate before taking any action to address the identified concerns. If the ISO chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls, including, if requested by the ISO in its sole discretion, supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls (and any supporting documentation, if applicable) or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable); or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls, including supporting documentation (which may include an organizational chart (or portion thereof) or equivalent information) that demonstrates the segregation of duties within such risk policies, procedures, and controls of the such customer or applicant, that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

The applicant's or customer's written policies, procedures, controls, and any supporting documentation, received by the ISO or its designee pursuant to this subsection (b) shall be treated as Confidential Information.

(c) Where an applicant or customer submits risk management policies, procedures, and controls, or supporting documentation to the ISO or its designee pursuant to any provision of subsection (b) above, the ISO or its designee shall assess that those policies, procedures, and controls conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit, and operational risk; (ii) segregating roles, responsibilities, and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Where, as a result of the assessment described above in this subsection (c), the ISO or its designee believes that the applicant's or customer's written policies, procedures, and controls do not conform to prudent risk management practices, then the ISO or its designee shall provide notice to the applicant or customer explaining the deficiencies. The applicant or customer shall revise its policies, procedures, and controls to address the deficiencies within 55 days after issuance of such notice. (If April 30 falls within that 55 day window, the ISO may choose not to require a separate submission on April 30 as described in subsection (b) above.) If an applicant's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the applicant will be prohibited from participating in the New England Markets. If a customer's revised written policies, procedures, and controls do not adequately address the deficiencies identified in the notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

3. Communications

Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has either established or contracted to establish procedures to effectively communicate with and respond to the ISO with respect to matters relating to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy. Such procedures must ensure, at a minimum, that at least one person with the ability and authority to address matters related to the ISO New England Financial Assurance Policy and the ISO New England Billing Policy on behalf of the customer or applicant, including the ability and authority to respond to requests for information and to arrange for additional financial assurance as necessary, is available from 9:00 a.m. to 5:00 p.m. Eastern Time on Business Days. Such procedures must also ensure that the ISO is kept informed about the current contact information (including phone numbers and e-mail addresses) for the person or people described above. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

4. Capitalization

(a) To be deemed as meeting the capitalization requirements, a customer or applicant shall either:

(i) be Rated and have a Governing Rating that is an Investment Grade Rating of BBB-/Baa3 or higher;

(ii) maintain a minimum Tangible Net Worth of one million dollars; or

(iii) maintain a minimum of ten million dollars in total assets, provided that, to meet this requirement, a customer or applicant may supplement total assets of less than ten million dollars with additional financial assurance in an amount equal to the difference between ten million dollars and the customer's or applicant's total assets in one of the forms described in Section X (any additional financial assurance provided pursuant to this Section II.A.4(a) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement (excluding FTR Financial Assurance Requirements).

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

5. Additional Eligibility Requirements

All customers and applicants shall at all times be:

(a) An "appropriate person," as defined in sections 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 1 *et seq.*);

(b) An "eligible contract participant," as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

(c) A "person who actively participates in the generation, transmission, or distribution of electric energy," as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

Each customer must demonstrate compliance with the requirements of this Section II.A.5 by submitting to the ISO on or before September 15, 2013 a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the customer is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the customer is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the customer's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the customer by a Senior Officer of the customer. A customer that fails to provide this certificate by September 15, 2013 shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

Each applicant must submit with its membership application a certificate in the form of Attachment 4 to the ISO New England Financial Assurance Policy that (i) certifies that the applicant is now and in good faith will seek to remain in compliance with the requirements of this Section II.A.5 and (ii) further certifies that if it no longer satisfies these requirements it shall immediately notify the ISO in writing and shall immediately cease all participation in the New England Markets. If the applicant is relying on section 4(c)(3)(F) of the Commodity Exchange Act, it shall accompany the certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the applicant's total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy. The certificate must be signed on behalf of the applicant by a Senior Officer of the applicant.

The ISO, at its sole discretion, may require any applicant or customer to submit to the ISO documentation in support of the certification provided pursuant to this Section II.A.5. If at any time the ISO becomes aware that a customer no longer satisfies the requirements of this Section II.A.5, the customer shall be immediately suspended and the ISO shall initiate termination proceedings against the customer.

6. Prior Uncured Defaults

In addition to, and not in limitation of Section IV of the ISO New England Financial Assurance Policy, an applicant who has a previous uncured payment default must cure such payment default by payment to the ISO of all outstanding and unpaid obligations, as well as meet all requirements for participation in the New England Markets contained in the ISO New England Financial Assurance Policy. For purposes of this Section II.A.6 and the ISO's evaluation of information disclosed pursuant to Section II of the ISO New England Financial Assurance Policy, the ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England Markets under a different name, affiliation, or organization, should be treated as the same customer or applicant that experienced the previous payment default. Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base, and the business engaged in prior to the attempted re-entry. Notwithstanding the foregoing, an applicant shall not be required to cure a payment default that has lawfully been discharged pursuant to the U.S. Bankruptcy Code.

B. Proof of Financial Viability for Applicants

Each Applicant must, with its membership application and at its own expense, submit proof of financial viability, as described below, satisfying the ISO requirements to demonstrate the Applicant's ability to meet its obligations. Each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit of greater than $0 under Section II.D or Section II.E below must submit to the ISO all current rating agency reports from Standard and Poor's ("S&P"), Moody's and/or Fitch (collectively, the "Rating Agencies"). Each Applicant, whether or not it intends to establish a Market Credit Limit or Transmission Credit Limit of greater than $0, must submit to the ISO audited financial statements for the two most recent years, or the period of its existence, if less than two years, and unaudited financial statements for its last concluded fiscal quarter if they are not included in such audited annual financial statements. These unaudited statements must be certified as to their accuracy by a Senior Officer of such Applicant, which, for purposes of ISO New England Financial Assurance Policy, 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 officer. These audited and unaudited statements must include in each case, but are not limited to, the following information to the extent available: balance sheets, income statements, statements of cash flows and notes to financial statements, annual and quarterly reports, and 10-K, 10-Q and 8-K Reports. If any of these financial statements are available on the internet, the Applicant may provide instead a letter to the ISO stating where such statement may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO, at the ISO's sole discretion (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; or (iii) compiled statements).

In addition, each Applicant, whether or not it intends to establish a Market Credit Limit or a Transmission Credit Limit, must submit to the ISO: (i) at least one (1) bank reference and three (3) utility company credit references, or in those cases where an Applicant does not have three (3) utility company credit references, three (3) major trade payable vendor references may be substituted; and (ii) relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant, or by its predecessor(s), if any; and (iii) a completed ISO credit application. In the case of certain Applicants, some of the information and documentation described in items (i) and (ii) of the immediately preceding sentence may not be applicable or available, and alternate requirements may be specified by the ISO or its designee in its sole discretion.

The ISO will not begin its review of a Market Participant's credit application or the accompanying material described above until full and final payment of that Market Participant's application fee.

The ISO shall prepare a report, or cause a report to be prepared, concerning the financial viability of each Applicant. In its review of each Applicant, the ISO or its designee shall consider all of the information and documentation described in this Section II. All costs incurred by the ISO in its review of the financial viability of an Applicant shall be borne by such Applicant and paid at the time that such Applicant is required to pay its first annual fee under the Participants Agreement. For an Applicant applying for transmission service from the ISO, all costs incurred by the ISO shall be paid prior to the ISO's filing of a Transmission Service Agreement. The report shall be provided to the Participants Committee or its designee and the affected Applicant within three weeks of the ISO's receipt of that Applicant's completed application, application fee, and Initial Market

Participant Financial Assurance Requirement, unless the ISO notifies the Applicant that more time is needed to perform additional due diligence with respect to its application.

C. Ongoing Review and Credit Ratings

1. Rated and Credit Qualifying Market Participants

A Market Participant that (i) has a corporate rating from one or more of the Rating Agencies, or (ii) has senior unsecured debt that is rated by one or more of the Rating Agencies, is referred to herein as "Rated." A Market Participant that is not Rated is referred to herein as "Unrated."

For all purposes in the ISO New England Financial Assurance Policy, for a Market Participant that is Rated, 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, shall be the "Governing Rating."

A Market Participant that is: (i) Rated and whose Governing Rating is an Investment Grade Rating; or (ii) Unrated and that satisfies the Credit Threshold is referred to herein as "Credit Qualifying." A Market Participant that is not Credit Qualifying is referred to herein as "Non-Qualifying."

For purposes of the ISO New England Financial Assurance Policy, "Investment Grade Rating" for a Market Participant (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

2. Unrated Market Participants

Any Unrated Market Participant that (i) has not been a Market Participant in the ISO for at least the immediately preceding 365 days; or (ii) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during such 365-day period; or (iii) is an FTR-Only Customer; or (iv) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Market Participant that does not meet any of the conditions in clauses (i), (ii), (iii) and (iv) of this paragraph is referred to herein as satisfying the "Credit Threshold."

For purposes of the ISO New England Financial Assurance Policy, "Current Ratio" on any date is 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; "Debt-to-Total Capitalization Ratio" on any date is 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; and "EBITDA-to-Interest Expense Ratio" on any date is 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. The "Debt-to-Total Capitalization Ratio" will not be considered for purposes of determining whether a Municipal Market Participant satisfies the Credit Threshold. Each of the ratios described in this paragraph shall be determined in accordance with international accounting standards or generally accepted accounting principles in the United States at the time of determination consistently applied.

3. Information Reporting Requirements for Market Participants

Each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis within 10 days of its becoming available and within 65 days after the end of the applicable fiscal quarter of such Market Participant, its balance sheet, which shall show sufficient detail for the ISO to assess the Market Participant's Tangible Net Worth. Unrated Market Participants having a Market Credit Limit or Transmission Credit Limit greater than zero shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Market Participant's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each Market Participant having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Market Participant, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Market Participant may provide instead a letter to the ISO stating where such information may be located and retrieved. If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-alone subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Market Participant or Unrated Market Participant that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section II.C.3 shall be accompanied by a written statement from a Senior Officer of the Market Participant or Unrated Market Participant certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm,

then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Market Participant to submit the financial statements and other information described in this subsection. The Market Participant shall provide the requested statements and other information within 10 days of such request. If a Market Participant fails to provide financial statements or other information as requested and the ISO determines that the Market Participant poses an unreasonable risk to the New England Markets, then the ISO may request that the Market Participant provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Market Participant's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section II.C.3 shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Market Participant fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Market Participant. If the Market Participant fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Market Participant.

A Market Participant may choose not to submit financial statements as described in this Section II.C.3, in which case the ISO shall use a value of $0.00 for the Market Participant's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Market Participant's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Market Participant may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section II.C.3. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Market Credit Limits

A credit limit for a Market Participant's Financial Assurance Obligations except FTR Financial Assurance Requirements (a "Market Credit Limit") shall be established for each Market Participant in accordance with this Section II.D.

1. Market Credit Limit for Non-Municipal Market Participants

A "Market Credit Limit" shall be established for each Rated Non-Municipal Market Participant in accordance with subsection (a) below, and a Market Credit Limit shall be established for each Unrated Non-Municipal Market Participant in accordance with subsection (b) below.

a. Market Credit Limit for Rated Non-Municipal Market Participants

As reflected in the following table, the Market Credit Limit of each Rated Non-Municipal Market Participant (other than an FTR-Only Customer) shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table, (ii) $50 million, or (iii) 20 percent (20%) of 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 ("TADO").

Investment Grade Rating		Percentage of Tangible Net Worth
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%

Below BBB-	Below Baa3	0.00%

An entity's "Tangible Net Worth" for purposes of the ISO New England Financial Assurance Policy on any date 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.

b. Market Credit Limit for Unrated Non-Municipal Market Participants

The Market Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

2. Market Credit Limit for Municipal Market Participants

The Market Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to the lesser of (i) 20 percent (20%) of TADO and (ii) $25 million. The Market Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

E. Transmission Credit Limits

A "Transmission Credit Limit" shall be established for each Market Participant in accordance with this Section II.E, which Transmission Credit Limit shall apply in accordance with this Section II.E. A Transmission Credit Limit may not be used to meet FTR Financial Assurance Requirements.

1. Transmission Credit Limit for Rated Non-Municipal Market Participants

The Transmission Credit Limit of each Rated Non-Municipal Market Participant shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Municipal Market Participant's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

2. Transmission Credit Limit for Unrated Non-Municipal Market Participant

The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that satisfies the Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Municipal Market Participant's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Municipal Market Participant that does not satisfy the Credit Threshold shall be $0.

3. Transmission Credit Limit for Municipal Market Participants

The Transmission Credit Limit for each Credit Qualifying Municipal Market Participant shall be equal to $25 million. The Transmission Credit Limit for each Non-Qualifying Municipal Market Participant shall be $0. The sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million.

F. Credit Limits for FTR-Only Customers

The Market Credit Limit and Transmission Credit Limit of each FTR-Only Customer shall be $0.

G. Total Credit Limit

The sum of a Rated Non-Municipal Market Participant's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Municipal Market Participant that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the limit set forth in Section II.D.1.a above) and its Transmission Credit Limit (up to the limit set forth in Section II.E.1 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Municipal Market Participant may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Municipal Market Participant does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

III. MARKET PARTICIPANTS' REQUIREMENTS

Each Market Participant that provides the ISO with financial assurance pursuant to this Section III must provide the ISO with financial assurance in one of the forms described in Section X below and in an amount equal to the amount required in order to avoid suspension under Section III.B below (the "Market Participant Financial Assurance Requirement"). A Market Participant's Market Participant Financial Assurance Requirement shall remain in effect as provided herein until the later of (a) 150 days after termination of the Market Participant's membership or (b) the end date of all FTRs awarded to the Market Participant and the final satisfaction of all obligations of the Market Participant providing that financial assurance; provided, however that financial assurances required by the ISO New England Financial Assurance Policy related to potential billing adjustments chargeable to a terminated Market Participant shall remain in effect until such billing adjustment request is finally resolved in accordance with the provisions of the ISO New England Billing Policy. Furthermore and without limiting the generality of the foregoing, (i) any portion of any financial assurance provided under the ISO New England Financial Assurance Policy that relates to a Disputed Amount shall not be terminated or returned prior to the resolution of such dispute, even if the Market Participant providing such financial assurance is terminated or voluntarily terminates its MPSA and otherwise satisfies all of its obligations to the ISO and (ii) the ISO shall not return or permit the termination of any financial assurance provided under the ISO New England Financial Assurance Policy by a Market Participant that has terminated its membership or been terminated to the extent that the ISO determines in its reasonable discretion that that financial assurance will be required under the ISO New England Financial Assurance Policy with respect to an unsettled liability or obligation owing from that Market Participant.

A Market Participant that knows that it is not satisfying its Market Participant Financial Assurance Requirement shall notify the ISO immediately of that fact.

A. Determination of Financial Assurance Obligations

For purposes of the ISO New England Financial Assurance Policy:

(i) a Market Participant's "Hourly Requirements" at any time will be the sum of (x) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been settled but not invoiced, plus (z) the Hourly Charges (excluding Daily FCM Charges) for such Market Participant that have been cleared but not settled which amount shall be calculated by the Hourly Charges Estimator. The Hourly Charges Estimator (which amount shall not be less than $0) shall be determined by the following formula:

$$\text{Hourly Charges Estimator} = \sum_{i=t-n+1}^{t} HC_i \times \text{LMP ratio} \times 1.15$$

Where:

t =	The last day that such Market Participant's Hourly Charges (excluding Daily FCM Charges) are fully settled;
n =	The number of days that such Market Participant's Day-Ahead Energy has been cleared but not settled;
HC =	The Hourly Charges (excluding Daily FCM Charges) for such Market Participant for a fully settled day; and
LMP ratio =	The average Day-Ahead Prices at the New England Hub over the period of cleared but not settled n days divided by the average Day-Ahead Prices at the New England Hub over the period of most recent fully settled n days. For purposes of this Section III.A.(i), the "New England Hub" shall mean the Hub located in Western and Central Massachusetts referred to as .H.INTERNAL_HUB;

(ii) A Market Participant's "Daily FCM Requirements" at any time will be the sum of (x) the Daily FCM Charges that have been invoiced but not paid (which amount shall not be less than $0), plus (y) the Daily FCM Charges that have been settled but not invoiced, plus (z) the Daily FCM Charges for such Market Participant that have been incurred but not settled which amount shall be calculated by the Daily FCM Obligation Estimator. The Daily FCM Obligation Estimator (which amount shall not be less than $0) shall be determined by the following formula:

Daily FCM Obligation Estimator = MAX(FCM_Daily_Credit_CM x NDAY_CM + FCM_Daily_Credit_PM x NDAY_PM + FCM_Charge_LD x NDAY_P2 x FCA_Price_Ratio, 0)

Where:

FCM_Daily_Credit_CM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the current month;

FCM_Daily_Credit_PM is the portion of the Daily FCM Charges that corresponds to Capacity Supply Obligations for the Market Participant in the month preceding the current month;

NDAY_CM is the number of days in the current month within the period from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

NDAY_PM is the number of days in the month preceding the current month within the period from the last day of the Daily FCM Charges have been settled to the current day (when financial assurance is assessed);

FCM_Charge_LD is the portion of the Daily FCM Charges that corresponds to Capacity Load Obligations for the Market Participant from the last day the Daily FCM Charges have been settled; and

NDAY_P2 is the number of days from the last day the Daily FCM Charges have been settled to the current day (when financial assurance is assessed) plus 2.

The FCA_Price_Ratio shall be calculated as the weighted average of the Capacity Clearing Prices for the Rest-of-Pool Capacity Zone for the relevant Capacity Commitment Periods divided by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day the Daily FCM Charges have been settled, as determined by the following formula:

FCA_Price_Ratio = (((Clearing Price_CCP_n x NDAY_P2_CCP_n) + (Clearing Price_CCP_{n+1} x NDAY_P2_CCP_{n+1}))/NDAY_P2)/(Clearing Price_CCP_n)

Where:

Clearing Price_CCP_n is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone corresponding to the Capacity Commitment Period that contains the last day that the Daily FCM Charges have been settled;

Clearing Price_CCP_{n+1} is the Capacity Clearing Price for the Rest-of-Pool Capacity Zone for the Capacity Commitment Period following CCP_n;

NDAY_P2_CCP_n is number of days in the CCP_n within NDAY_P2; and

NDAY_P2_CCP_{n+1} is number of days in the CCP_{n+1} within NDAY_P2.

(iii) a Market Participant's "Non-Hourly Requirements" at any time will be determined by averaging that Market Participant's Non-Hourly Charges but not include: (A) the amount due from or to such Market Participant for FTR transactions, (B) any amounts due from such Market Participant for the Forward Capacity Market, (C) any amounts due under Section 14.1 of the RNA, (D) any amounts due for NEPOOL GIS API Fees, and (E) the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Market Participant) over the two most recently invoiced calendar months; provided that such Non-Hourly Requirements shall in no event be less than zero;

(iv) a Market Participant's "Transmission Requirements" at any time will be determined by averaging that Market Participant's Transmission Charges over the two most recently invoiced calendar months; provided that such Transmission Requirements shall in no event be less than $0;

(v) a Market Participant's Virtual Requirements at any time will equal the amount of all unsettled Increment Offers and Decrement Bids submitted by such Market Participant at such time (which amount of unsettled Increment Offers and Decrement Bids will be calculated by the ISO according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and posted on the ISO's website);

(vi) a Market Participant's "Financial Assurance Obligations" at any time will be equal to the sum at such time of:

a. such Market Participant's Hourly Requirements; plus
b. such Market Participant's Daily FCM Requirements; plus
c. such Market Participant's Virtual Requirements; plus
d. such Market Participant's Non-Hourly Requirements times 2.50 (subject to Section X.D with respect to Provisional Members); plus
e. such Market Participant's "FTR Financial Assurance Requirements" under Section VI below; plus
f. such Market Participant's "FCM Financial Assurance Requirements" under Section VII below; plus
g. the amount of any Disputed Amounts received by such Market Participant; and

(vii) a Market Participant's "Transmission Obligations" at any time will be such Market Participant's Transmission Requirements times 2.50.

To the extent that the calculations of the components of a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) as described above produce positive and negative values, such components may offset each other; provided, however, that a Market Participant's Financial Assurance Obligations shall never be less than zero.

B. Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension from the New England Markets

1. Credit Test Calculations and Allocation of Financial Assurance

The financial assurance provided by a Market Participant shall be applied as described in this Section.

(a) "Market Credit Test Percentage" is equal to a Market Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements) divided by the sum of its Market Credit Limit and any financial assurance allocated as described in subsection (d) below.

(b) "FTR Credit Test Percentage" is equal to a Market Participant's FTR Financial Assurance Requirements divided by any financial assurance allocated as described in subsection (d) below.

(c) "Transmission Credit Test Percentage" is equal to a Market Participant's Transmission Obligations divided by the sum of its Transmission Credit Limit and any financial assurance allocated as described in subsection (d) below.

(d) A Market Participant's financial assurance shall be allocated as follows:

(i) financial assurance shall be first allocated so as to ensure that the Market Participant's Market Credit Test Percentage is no greater that 100%;

(ii) any financial assurance that remains after the allocation described in subsection (d) (i) shall be allocated so as to ensure that the Market Participant's FTR Credit Test Percentage is no greater than 100%;

(iii) any financial assurance that remains after the allocation described in subsection (d) (ii) shall be allocated so as to ensure that the Market Participant's Transmission Credit Test Percentage is no greater than 100%;

(iv) if any financial assurance remains after the allocations described in subsection (d) (iii), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 89.99%;

(v) if any financial assurance remains after the allocation described in subsection (d) (iv), then that remaining financial assurance shall be allocated by repeating the steps described in subsections (d) (i), (d) (ii), and (d) (iii) to ensure that the respective test percentages are no greater than 79.99%;

(vi) any financial assurance that remains after the allocations described in subsection (d) (v) shall be allocated to the Market Credit Test Percentage.

2. Notices

a. 80 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant.

b. 90 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) , then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%), the ISO shall issue notice thereof to such Market Participant. The ISO shall also issue a 90 percent (90%) notice to a Market Participant and take certain other actions under the circumstances described in Section III.B.2.c below.

c. 100 Percent Test

When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or when the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equal zero, then, in addition to the actions to be taken when the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 80 percent (80%) and 90 percent (90%), (i) the ISO shall issue notice thereof to such Market Participant, (ii) that Market

Participant shall be immediately suspended from submitting Increment Offers and Decrement Bids until such time when its Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are less than or equal to 100 percent (100%), and (iii) if sufficient financial assurance to lower the Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 100 percent (100%) or, in the case of a Market Participant that has received one to five notices that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) in the previous 365 days (not including the instant notice), sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%), is not provided by 8:30 a.m. Eastern Time on the next Business Day, (a) the event shall be a Financial Assurance Default; (b) the ISO shall issue notice thereof to such Market Participant, to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contacts for all Market Participants, and (c) such Market Participant shall be suspended from: (1) the New England Markets, as provided below; (2) receiving transmission service under any existing or pending arrangements under the Tariff or scheduling any future transmission service under the Tariff; (3) voting on matters before the Participants Committee and NEPOOL Technical Committees; (4) entering into any future transactions in the FTR system; and (5) submitting an offer of Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction in the Forward Capacity Market, in each case until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 100 percent (100%) or less. In addition to all of the provisions above, any Market Participant that has received six or more notices in the previous 365 days that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) shall receive a notice thereof and shall be required to maintain sufficient financial assurance to keep such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage at less than or equal to 90 percent (90%). If such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage exceeds 90 percent (90%), the ISO shall issue a notice thereof to such Market Participant. If sufficient financial assurance to lower such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage to less than or equal to 90 percent (90%) is not provided by 8:30 a.m. Eastern Time on the next Business Day, then the consequences described in subsections (a), (b) and (c) of Section III.B.2.c (iii) above shall apply until such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are at 90 percent (90%) or less.

However, when a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) or 90 percent (90%), as applicable under this Section III.B.2.c, solely because its Investment Grade Rating is downgraded by one grade and the resulting grade is BBB-/Baa3 or higher, then (x) for five Business Days after such downgrade, such downgrade shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage and (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such downgrade if such Market Participant cures such default within such five Business Day period. When a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent solely because a letter of credit is valued at $0 prior to the termination of that letter of credit, as described in Section X.B, then the ISO, in its sole discretion, may determine that: (x) for five Business Days after such change in the valuation of the letter of credit, such valuation shall not by itself cause a change to such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage; and/or (y) no notice shall be sent and none of the other actions described in this Section III.B shall occur with respect to such valuation if such Market Participant cures such default within such five Business Day period.

Notwithstanding the foregoing, a Market Participant shall neither (x) receive a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) nor (y) be suspended under this Section III.B if (i) the amount of financial assurance necessary for that Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit

Test Percentage to get to 100 percent (100%) or lower is less than $1,000 or (ii) that Market Participant's status with the ISO has been terminated.

3. Suspension from the New England Markets

a. General

The suspension of a Market Participant, and any resulting annulment, termination or removal of OASIS reservations, removal from the settlement system and the FTR system, suspension of the ability to offer Non-Commercial Capacity or participate in a substitution auction in the Forward Capacity Market, drawing down of financial assurance, rejection of Increment Offers and Decrement Bids, and rejection of bilateral transactions submitted to the ISO, shall not limit, in any way, the ISO's right to invoice or collect payment for any amounts owed (whether such amounts are due or becoming due) by such suspended Market Participant under the Tariff or the ISO's right to administratively submit a bid or offer of a Market Participant's Non-Commercial Capacity in any Forward Capacity Auction or any reconfiguration auction or to make other adjustments under Market Rule 1.

In addition to the notices provided herein, the ISO will provide any additional information required under the ISO New England Information Policy.

Each notice issued by the ISO pursuant to this Section III.B shall indicate whether the subject Market Participant has a registered load asset. If the ISO has issued a notice pursuant to this Section III.B and subsequently the subject Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%), such Market Participant may request the ISO to issue a notice stating such fact. However, the ISO shall not be obligated to issue such a notice unless, in its sole discretion, the ISO concludes that such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, and Transmission Credit Test Percentage are equal to or less than 100 percent (100%).

Notwithstanding the foregoing, if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equals or exceeds 90 percent (90%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will not be issued.

If a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent (100%) as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, and, but for such Increment Offers and/or Decrement Bids or such bilateral transactions, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, a notice will be issued only to such Market Participant, and such Market Participant shall be "suspended" as described below.

Any such suspension as a result of one or more Increment Offers or Decrement Bids submitted by a Market Participant, or as a result of the submission to the ISO of one or more bilateral transactions to which the Market Participant is a party, shall take effect immediately upon submission of such Increment Offers and/or Decrement Bids or such bilateral transactions to remain in effect until such Market Participant is in compliance with the ISO New England Financial Assurance Policy, notwithstanding any provision of this Section III.B to the contrary.

If a Market Participant is suspended from the New England Markets in accordance with the provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy, then the provisions of this Section III.B shall control notwithstanding any other provision of the Tariff to the contrary. A suspended Market Participant shall have no ability so long as it is suspended (i) to be reflected in the ISO's settlement system, including any bilateral transactions, as either a purchaser or a seller of any products or services sold through the New England Markets (other than (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, (ii) to submit Demand Bids, Decrement Bids or Increment Offers in the New England Markets, (iii) to submit offers for Non-Commercial Capacity in any Forward Capacity Auction or reconfiguration auction or acquire Non-Commercial Capacity through a Capacity Supply Obligation Bilateral, or (iv) to submit supply offers or demand bids in any Forward Capacity Market substitution auction. Any transactions, including bilateral transactions with a suspended Market Participant (other than transactions for (A) Commercial Capacity and (B) Non-Commercial Capacity during the Non-Commercial Capacity Cure Period) that cause such suspended Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the other Market Participants and any Demand Bids, Decrement Bids, Increment Offers, and Export Transactions submitted by a suspended Market Participant shall be deemed to be terminated for purposes of the Day-Ahead Energy Market clearing and the ISO's settlement system. If a Market Participant has provided the financial assurance required for a Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, then that Capacity Supply Obligation Bilateral or Annual Reconfiguration Transaction, respectively, will not be deemed to be terminated when that Market Participant is suspended.

b. Load Assets

Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

c. FTRs

If a Market Participant is suspended from entering into future transactions in the FTR system, such Market Participant shall retain all FTRs held by it but shall be prohibited from acquiring any additional FTRs during the course of its suspension. It is intended that any suspension under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy will occur promptly, and the definitive timing of any such suspension shall be determined by the ISO from time to time as reported to the NEPOOL Budget and Finance Subcommittee, and shall be posted on the ISO website.

d. Virtual Transactions

Notwithstanding the foregoing, if a Market Participant is suspended in accordance with the provisions of the ISO New England Financial Assurance Policy as a result of one or more Increment Offers or Decrement Bids submitted by that Market Participant and, but for such Increment Offers and/or Decrement Bids, such Market Participant would be in compliance with the ISO New England Financial Assurance Policy, then such suspension shall be limited to (i) the immediate "last in, first out" rejection of pending individual uncleared Increment Offers and Decrement Bids submitted by that Market Participant (it being understood that Increment Offers and Decrement Bids are batched by the ISO in accordance with the time, and that Increment Offers and Decrement Bids will be rejected by the batch); and (ii) the suspension of that Market Participant's ability to submit additional Increment Offers and Decrement Bids unless and until it has complied with the ISO New England Financial Assurance Policy, and the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of that Market Participant after giving effect to the immediate rejection of that Market Participant's Increment Offers and Decrement Bids described in clause (i).

e. Bilateral Transactions

If the sum of the financial assurance and credit limits of a Market Participant that has financial assurance requirements equals zero and that Market Participant would be in compliance with the ISO New England Financial Assurance Policy but for the submission of bilateral transactions to the ISO to which the Market Participant is a party, or if a Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeds 100 percent as a result of one or more bilateral transactions submitted to the ISO to which the Market Participant is a party, then the consequences described in subsection (a) above shall be limited to: (i) rejection of any pending bilateral transactions to which a Market Participant is a party that cause the Market Participant to incur a financial obligation in the ISO's settlement system or any liability to the ISO, NEPOOL, or the Market Participants, such that the aggregate value of the pending bilateral transactions submitted by all Market Participants is maximized (recognizing the downstream effect that rejection of a bilateral transaction may have on the Market Credit Test Percentages, FTR Credit Test Percentages, or Transmission Credit Test Percentages of other Market Participants), while ensuring that the financial assurance requirements of each Market Participant are satisfied; and (ii) suspension of that Market Participant's ability to submit additional bilateral transactions until it has complied with the ISO New England Financial Assurance Policy (the determination of compliance for these purposes will take into account the level of aggregate outstanding obligations of the Market Participant after giving effect to the immediate rejection of the bilateral transactions to which the Market Participant is a party as described in clause (i) above). In the case of a bilateral transaction associated with the Day-Ahead Energy Market, the ISO will provide notice to a Market Participant that would be in default of the ISO New England Financial Assurance Policy as a result of the bilateral transaction, and the consequences described in clauses (i) and (ii) above shall only apply if the Market Participant fails to cure its default by 6:00 p.m. Eastern Time of that same Business Day. In the case of a Capacity Load Obligation Bilateral, the consequences described in clauses (i) and (ii) above shall apply if the Market Participant does not cure its default within one Business Day after notification that a Capacity Load Obligation Bilateral caused the default. Bilateral transactions that transfer Forward Reserve Obligations and Supplemental Availability Bilaterals are not subject to the provisions of this Section III.B.3(e).

4. Serial Notice and Suspension Penalties

If either (x) a Market Participant is suspended from the New England Markets because of a failure to satisfy its Financial Assurance Requirements in accordance with the provisions of the ISO New England Financial Assurance Policy or (y) a Market Participant receives more than five notices that its Market Credit Test Percentage, FTR Credit Test Percentage or Transmission Credit Test Percentage has exceeded 100 percent (100%) in any rolling 365-day period, then such Market Participant shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 365-day period. If a Market Participant receives a notice that its Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage has exceeded 100 percent (100%) in the same day, then only one of those notices will count towards the five notice limit. All penalties paid under this paragraph shall be deposited in the Late Payment Account maintained under the ISO New England Billing Policy.

C. Additional Financial Assurance Requirements for Certain Municipal Market Participants

Notwithstanding the other provisions of the ISO New England Financial Assurance Policy and in addition to the other obligations hereunder, a Credit Qualifying Municipal Market Participant that is not a municipality (which, for purposes of this Section III.C, does not include an agency or subdivision of a municipality) must provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation, unless either: (1) that Credit Qualifying Municipal Market Participant has a corporate Investment Grade Rating from one or more of the Rating Agencies; or (2) that Credit Qualifying Municipal Market Participant has an Investment Grade Rating from one or more of the Rating Agencies for all of its rated indebtedness; or (3) that Credit Qualifying Municipal Market Participant provides the ISO with an opinion of counsel that is acceptable to the ISO confirming that amounts due to the ISO under the Tariff have priority over, or have equal priority with, payments due on the debt on which the Credit Qualifying Municipal Market Participant's Investment Grade Rating is based. Each legal opinion provided under clause (3) of this Section III.C will be updated no sooner than 60 days and no later than 30 days before each reconfiguration auction that precedes a Capacity Commitment Period to which such legal opinion relates, and if that update is not provided or that update is not acceptable to the ISO, the applicable Credit Qualifying Municipal Market Participant must either satisfy one of the other clauses of this Section III.C or provide additional financial assurance in one of the forms described in Section X below in an amount equal to its FCM Financial Assurance Requirements at the time of calculation.

IV. CERTAIN NEW AND RETURNING MARKET PARTICIPANTS REQUIREMENTS

A new Market Participant or a Market Participant other than an FTR-Only Customer, or a Governance Only Member whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months (a "Returning Market Participant") is required to provide the ISO, for three months in the case of a new Market Participant and six months in the case of a Returning Market Participant, financial assurance in one of the forms described in Section X below equal to any amount of additional financial assurance required to meet the capitalization requirements described in Section II.A.4 plus the greater of (a) its Financial Assurance Requirement or (b) its "Initial Market Participant Financial Assurance Requirement." A new Market Participant's or a Returning Market Participant's Initial Market

Participant Financial Assurance Requirement must be provided to the ISO no later than one Business Day before commencing activity in the New England Markets or commencing transmission service under the Tariff, and shall be determined by the following formula:

$$FAR = G + T + L + E$$

Where FAR is the Initial Market Participant Financial Assurance Requirement and G, T, L and E are determined by the following formulas:

$G = (MW_g \times Hr_{DA} \times D \times 3.25) + (MW_g \times Hr_{MIS} \times S_2 \times 3.25)$;

Where:

$MW_g =$ Total nameplate capacity of the Market Participant's generation units that have achieved commercial operation;

$Hr_{DA} =$ The number of hours of generation that any such generation unit could be bid in the Day-Ahead Energy Market before it could be removed if such unit tripped, as determined by the ISO in its sole discretion;

$D =$ The maximum observed differential between Energy prices in the Day-Ahead and Real-Time Energy Markets during the prior calendar year ("Maximum Energy Price Differential"), as determined by the ISO in its sole discretion;

$Hr_{MIS} =$ The standard number of hours between generation and the issuance of initial Market Information Server ("MIS") settlement reports including projected generation activity for such units, as determined by the ISO in its sole discretion; and

$S_2 =$ The per MW amount assessed pursuant to Schedule 2 of Section IV.A of this Tariff, as determined by the ISO.

$T =$ $MW_t \times Hr_{MIS} \times (D + S_{2\text{-}3}) \times 3.25$;

Where: MW_t = Number of MWs to be traded in the New England Markets as reasonably projected by the new Market Participant or the Returning Market Participant;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

D = Maximum Energy Price Differential; and

$S_{2\text{-}3}$ = The per MWh amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO.

$$L = (MW_l \times LF \times Hr_{MIS} \times (EP + S_{2\text{-}3}) \times 3.25) + (MW_l \times Hr_{MIS} \times TC \times 3.25)$$

Where:

MW_l = MWs of Real-Time Load Obligation (as defined in Market Rule 1) of the new Market Participant or Returning Market Participant;

LF = Average load factor in New England, as determined annually by the ISO in its sole discretion;

Hr_{MIS} = The standard number of hours between generation and the issuance of initial MIS settlement reports including projected generation activity, as determined by the ISO in its sole discretion;

EP = The average price of Energy in the Day-Ahead Energy Market for the most recent calendar year for which information is available from the Annual Reports published by the ISO, as determined by the ISO in its sole discretion;

$S_{2\text{-}3}$ = The per MW amount assessed pursuant to Schedules 2 and 3 of Section IV.A of the Tariff, as determined annually by the ISO; and

TC = The hourly transmission charges per MW_1 assessed under the Tariff (other than Schedules 1, 8 and 9 of Section II of the Tariff), as determined annually by the ISO.

E = (SE) x 3.25

Where:

SE = Average monthly share of Participant Expenses for the applicable Sector.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 80 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 80 percent (80%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV is 90 percent or more of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage equaled or exceeded 90 percent (90%) under Section III.B above.

If a new Market Participant's or a Returning Market Participant's Initial Market Participant Financial Assurance Requirement during the time period that it is subject to this Section IV exceeds 100 percent of the available amount of the financial assurance provided by that new Market Participant or Returning Market Participant, it shall have the same effect as if such Market Participant's Market Credit Test Percentage, FTR Credit Test Percentage, or Transmission Credit Test Percentage exceeded 100 percent (100%) under Section III.B above.

V. NON-MARKET PARTICIPANT TRANSMISSION CUSTOMERS REQUIREMENTS

A. Ongoing Financial Review and Credit Ratings

1. Rated Non-Market Participant Transmission Customer and Transmission Customers

Each Rated Non-Market Participant Transmission Customer that does not currently have an Investment Grade Rating must provide an appropriate form of financial assurance as described in Section X below.

2. Unrated Non-Market Participant Transmission Customers

Any Unrated Non-Market Participant Transmission Customer that (i) has defaulted on any of its obligations under the Tariff (including without limitation its obligations hereunder and under the ISO New England Billing Policy) during the immediately preceding 365-day period; or (ii) does not have a Current Ratio of at least 1.0, a Debt-to-Total Capitalization Ratio of 0.6 or less, and an EBITDA-to-Interest Expense Ratio of at least 2.0 must provide an appropriate form of financial assurance as described in Section X below. An Unrated Non-Market Participant Transmission Customer that does not meet either of the conditions described in clauses (i) and (ii) of this paragraph is referred to herein as satisfying the "NMPTC Credit Threshold."

B. NMPTC Credit Limits

1. NMPTC Market Credit Limit

A Market Credit Limit shall be established for each Non-Market Participant Transmission Customer as set forth in this Section V.B.1.

The Market Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the least of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth (as reflected in the following table); (ii) $50 million; or (iii) 20 percent (20%) of TADO:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%

AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%
A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the least of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth, (ii) $25 million or (iii) 20 percent (20%) of TADO. The Market Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

2. NMPTC Transmission Credit Limit

A Transmission Credit Limit shall be established for each Non-Market Participant Transmission Customer in accordance with this Section V.B.2.

The Transmission Credit Limit of each Rated Non-Market Participant Transmission Customer shall at any time be equal to the lesser of: (i) the applicable percentage of such Rated Non-Market Participant Transmission Customer's Tangible Net Worth as listed in the following table or (ii) $50 million:

Investment Grade Rating		**Percentage of Tangible Net Worth**
S&P/Fitch	**Moody's**	
AAA	Aaa	5.50%
AA+	Aa1	5.50%
AA	Aa2	4.50%
AA-	Aa3	4.00%
A+	A1	3.05%
A	A2	2.85%

A-	A3	2.60%
BBB+	Baa1	2.30%
BBB	Baa2	1.90%
BBB-	Baa3	1.20%
Below BBB-	Below Baa3	0.00%

The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that satisfies the NMPTC Credit Threshold shall at any time be equal to the lesser of: (i) 0.50 percent (0.50% or ½ of 1%) of such Unrated Non-Market Participant Transmission Customer's Tangible Net Worth or (ii) $25 million. The Transmission Credit Limit of each Unrated Non-Market Participant Transmission Customer that does not satisfy the NMPTC Credit Threshold shall be $0.

3. NMPTC Total Credit Limit

The sum of a Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall not exceed $50 million and the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates shall not exceed $50 million. No later than five Business Days prior to the first day of each calendar quarter, and no later than five Business Days after any Affiliate change, each Rated Non-Market Participant Transmission Customer that has a Market Credit Limit and a Transmission Credit Limit shall determine the amounts to be allocated to its Market Credit Limit (up to the amount set forth in Section V.B.1 above) and its Transmission Credit Limit (up to the amount set forth in Section V.B.2 above) such that the sum of its Market Credit Limit and its Transmission Credit Limit are equal to not more than $50 million and such that the sum of the Market Credit Limits and Transmission Credit Limits of entities that are Affiliates do not exceed $50 million and shall provide the ISO with that determination in writing. Each Rated Non-Market Participant Transmission Customer may provide such determination for up to four consecutive calendar quarters. If a Rated Non-Market Participant Transmission Customer does not provide such determination, then the ISO shall use the amounts provided for the previous calendar quarter. If no such determination is provided, then the ISO shall apply an allocation of $25 million each to the Market Credit Limit and Transmission Credit Limit, which values shall also be used in allocating the $50 million credit limit among Affiliates. If the sum of the amounts for Affiliates is greater than $50 million, then the ISO shall reduce the amounts (proportionally to the amounts provided by each Affiliate, or to the allocation applied by the ISO in the case of an Affiliate that provided no determination) such that the sum is no greater than $50 million.

C. Information Reporting Requirements for Non-Market Participant Transmission Customers

Each Rated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Rated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Rated Non-Market Participant Transmission Customer's Tangible Net Worth. In addition, each Rated Non-Market Participant Transmission Customer that has an Investment Grade Rating having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of their becoming available and within 120 days after the end of the fiscal year of such Rated Non-Market Participant Transmission Customer, balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). If any of this financial information is available on the internet, the Rated Non-Market Participant Transmission Customer may provide instead a letter to the ISO stating where such information may be located and retrieved.

Each Unrated Non-Market Participant Transmission Customer having a Market Credit Limit or Transmission Credit Limit greater than zero or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, on a quarterly basis, within 10 days of their becoming available and within 65 days after the end of the applicable fiscal quarter of such Unrated Non-Market Participant Transmission Customer, its balance sheet, which shall show sufficient detail for the ISO to assess the Unrated Non-Market

Participant Transmission Customer's Tangible Net Worth. Unrated Non-Market Participant Transmission Customers having a Market Credit Limit or Transmission Credit Limit greater than $0 shall also provide additional financial statements, which shall show sufficient detail for the ISO to calculate such Unrated Non-Market Participant Transmission Customer's Current Ratio, Debt-to-Total Capitalization Ratio and EBITDA-to-Interest Expense Ratio. In addition, each such Unrated Non-Market Participant Transmission Customer that satisfies the Credit Threshold and has a Market Credit Limit or Transmission Credit Limit of greater than $0 or meeting the capitalization requirements by maintaining a minimum Tangible Net Worth or minimum total assets as described in Section II.A.4(a) shall submit to the ISO, annually within 10 days of becoming available and within 120 days after the end of the fiscal year of such Unrated Non-Market Participant Transmission Customer balance sheets and income statements (balance sheets and income statements that are part of audited financial statements shall be submitted if available; if such balance sheets and income statements are not available, then another alternative form of financial statements accepted by the ISO as described below may be submitted). Where any of the above financial information is available on the internet, the Unrated Non-Market Participant Transmission Customer may provide the ISO with a letter stating where such information may be located and retrieved.

If any of the information or documentation required by this section is not available, alternate requirements may be specified by the ISO (such alternate requirements may include, but are not limited to: (i) consolidating statements or other financial statements (in the case of a stand-along subsidiary) that are certified as to their accuracy and basis of accounting (in accordance with international accounting standards or generally accepted accounting principles in the United States) by an officer of the entity with the title of chief financial officer or equivalent position; (ii) reviewed statements; (iii) compiled statements; (iv) internally prepared statements; or (v) tax returns).

Except in the case of a Non-Market Participant Transmission Customer that submits audited financial statements to the ISO, financial statements submitted to the ISO pursuant to this Section V.C shall be accompanied by a written statement from a Senior Officer of the Non-Market Participant Transmission Customer certifying the accuracy of those financial statements. If an attestation was made by an independent accounting firm,

then the written statement shall indicate the level of attestation made; if no attestation was made by an independent accounting firm, then no such indication is required.

Notwithstanding any other provision in this subsection, the ISO may require any Non-Market Participant Transmission Customer to submit the financial statements and other information described in this subsection. The Non-Market Participant Transmission Customer shall provide the requested statements and other information within 10 days of such request. If a Non-Market Participant Transmission Customer fails to provide financial statements or other information as requested and the ISO determines that the Non-Market Participant Transmission Customer poses an unreasonable risk to the New England Markets, then the ISO may request that the Non-Market Participant Transmission Customer provide additional financial assurance in an amount no greater than $10 million, or take other measures to substantiate the Non-Market Participant Transmission Customer's ability to safely transact in the New England Markets (any additional financial assurance provided pursuant to this Section V.C shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy). If the Non-Market Participant Transmission Customer fails to comply with such a request from the ISO, then the ISO may issue a notice of suspension or termination to the Non-Market Participant Transmission Customer. If the Non-Market Participant Transmission Customer fails to comply with the ISO's request within 5 Business Days from the date of issuance of the notice of suspension or termination, then the ISO may suspend or terminate the Non-Market Participant Transmission Customer.

A Non-Market Participant Transmission Customer may choose not to submit financial statements as described in this Section V.C, in which case the ISO shall use a value of $0.00 for the Non-Market Participant Transmission Customer's total assets and Tangible Net Worth for purposes of the capitalization assessment described in Section II.A.4(a) and such Non-Market Participant Transmission Customer's Market Credit Limit and Transmission Credit Limit shall be $0.00.

A Non-Market Participant Transmission Customer may choose to provide additional financial assurance in an amount equal to $10 million in lieu of providing financial statements under this Section V.C. Such amount shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy but shall be sufficient to meet the capitalization requirements in Section II.A.4(a)(iii).

D. Financial Assurance Requirement for Non-Market Participant Transmission Customers

Each Non-Market Participant Transmission Customer that provides additional financial assurance pursuant to the ISO New England Financial Assurance Policy must provide the ISO with financial assurance in one of the forms described in Section X below and in the amount described in this Section V.D (the "NMPTC Financial Assurance Requirement").

1. Financial Assurance for ISO Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance such that the sum of its Market Credit Limit and that additional financial assurance shall at all times be at least equal to the sum of:

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market Participant Transmission Customer.

2. Financial Assurance for Transmission Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance, and the Settlement Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled. In no event will the FTR Settlement Risk Financial Assurance be less than $0.

B. Unsettled FTR Financial Assurance

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR Financial Assurance" for all FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsettled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial

Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.

C. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.

D. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance obligations hereunder) in place at the time an FTR Auction into which it has bid closes, then, in addition to the other consequences described in the ISO New England Financial Assurance Policy, all bids submitted by that Designated FTR Participant for that FTR Auction will be rejected. The Designated FTR Participant will be allowed to participate in the next FTR Auction held provided it meets all requirements for such participation, including without limitation those set forth herein. Each Designated FTR Participant must maintain the requisite additional financial assurance equal to its FTR Financial Assurance Requirements for the duration of the FTRs awarded to it. The amount of any additional financial assurance provided by a Designated FTR Participant in connection with an unsuccessful bid in an FTR Auction which, as a result of such bid being unsuccessful, is in excess of its FTR Financial Assurance Requirements will be held by the ISO and will be applied against future FTR bids by and awards to that Designated FTR Participant unless that Designated FTR Participant requests in writing to have such excess financial assurance returned to it. Prior to returning any financial assurance to a Designated FTR Participant, the ISO shall use such financial assurance to satisfy any overdue obligations of that Designated FTR Participant. The ISO shall only return to that

Designated FTR Participant the balance of such financial assurance after all such overdue obligations have been satisfied.

VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero. FCM Delivery Financial Assurance is calculated according to the following formula:

FCM Delivery Financial Assurance = [DFAMW x PE x max[(ABR – CWAP), 0.1] x SF x DF] – MCC

Where:

MCC (monthly capacity charge) equals monthly capacity payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June	2.000;
December and July	1.732;

January and August	1.414;
All other months	1.000.

DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the "FCM Deposit").

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the "Non-Commercial Capacity FA Amount");

(ii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the next annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was awarded, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to two (2) times the Non-Commercial Capacity FA Amount; and

(iii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was accepted, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.

b. Non-Commercial Capacity Participating in the Ninth Forward Capacity Auction and All Forward Capacity Auctions Thereafter

A Designated FCM Participant offering Non-Commercial Capacity into the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero:

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference between: (x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, except that for monthly Capacity Supply Obligation Bilaterals, one of the following prices will be used:

    (i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

    (ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those to be settled by the ISO) that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) the applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

(iii) If neither subsection (i) nor (ii) applies, then the applicable Annual Reconfiguration Transaction price shall be used.

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the

ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. [Reserved for Future Use]

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the "Non-Commercial Capacity Cure Period"), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply

Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with

respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)) and the current month FCM charges are prorated to the proportion of remaining days in the month. The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. Financial Assurance for Annual Reconfiguration Transactions

A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

VIII. [Reserved]

IX. THIRD-PARTY CREDIT PROTECTION

The ISO shall obtain third-party credit protection, in the form of credit insurance coverage ("Credit Coverage"), on terms acceptable to the ISO in its reasonable discretion at least in an amount covering collectively the Credit Qualifying Rated Market Participants based on the formula below. Notwithstanding the foregoing, if the entity providing such Credit Coverage cannot provide the amount required by this Section IX, the ISO will reduce the required coverage for all Credit Qualifying Rated Market Participants on a pro rata basis. The total amount of the Credit Coverage shall be at least the aggregate of the following formula; provided, however, if the entity providing the Credit Coverage denies coverage (in whole or in part) for any Credit Qualifying Rated Market Participant based on its rights under the insurance policy, the ISO will use reasonable efforts to obtain documentation regarding the denial and will make reasonable efforts to appeal such denial. For each Credit Qualifying Rated Market Participant, the portion of the Credit Coverage shall be the lesser of: (A) the sum of (x) 2.5 times the average Hourly Charges for such Credit Qualifying Rated Market Participant within the previous fifty-two calendar weeks plus (y) 2.5 times the sum of the average Non-Hourly Charges (excluding charges or credits related to FTR transactions) and the average Transmission Charges for such Credit Qualifying Rated Market Participant within the previous twelve calendar months; or (B) $50 million. For any Credit Qualifying Rated Market Participant, the applicable amount of the Credit Coverage shall be adjusted monthly if the above formula produces a change that is either (A) 10% or greater, or (B) greater than $100,000. The Credit Coverage shall be provided by an insurance company rated "A-" or better by A.M. Best & Co. or "A" or better by S&P. The cost of the Credit Coverage obtained for each calendar year shall be allocated to all Credit Qualifying Rated Market Participants pro rata based, for each Credit Qualifying Rated Market Participant, on the average amount of the Invoices issued to that Credit Qualifying Rated Market Participant under the ISO New England Billing Policy in the preceding calendar year. Each Credit Qualifying Rated Market Participant shall provide the ISO with such information as may be reasonably necessary for the ISO to obtain the Credit Coverage at the lowest possible cost.

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy or the form of Control Agreement posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of

1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Requirements for Banks

Each bank issuing a letter of credit that serves as additional financial assurance must meet the requirements of this Section X.B.1. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers." The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly. To be included on the List of Eligible Letter of Credit Issuers, the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank and either: (i) be recognized by the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's or "A-" by Fitch so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer as described in clause (i) above; or (iii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch and be approved by the ISO in its sole discretion (the ISO will promptly advise the NEPOOL Budget and Finance Subcommittee of any additional bank approved by it under this provision). Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses if any applicable rating from the Rating Agencies falls below the levels listed in those clauses. In addition, no Posting Entity may provide a letter of credit that has been issued or confirmed by a bank that is an Affiliate of that Market Participant. If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy any of the criteria set forth above, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure to replace the letter of credit with a letter of credit from a bank satisfying those criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. In the case of a bank that is removed from CME list of approved letter of credit banks, the ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. No letter of credit bank may issue or confirm letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued or confirmed by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue or confirm letters of credit in favor of the ISO, (C) any letters of credit issued or confirmed by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued or confirmed by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.1.

Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.

2. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a Letter of Credit in the Form of Attachment 2, or (b) December 31, 2021. Any letter of credit provided for a new Posting Entity must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing a cash deposit in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of the cash deposited by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing a cash deposit or letter of credit in accordance with this Section X but shall not be satisfied through the provision of the cash deposit described in this Section X.C. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of the cash deposit initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that cash deposit to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: 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 Principals imposed 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; the filing of a material lawsuit that could materially adversely impact current or future financial results; or a significant change in the Market Participant's or Non-Market Participant Transmission Customer's market capitalization. A Market Participant's or Non-Market Participant Transmission Customer's failure to timely disclose a Material Adverse Change in its financial status may result in termination proceedings by the ISO. If the ISO determines that there is a Material Adverse Change in the financial condition of a Market Participant- or Non-Market Participant Transmission Customer, then the ISO shall provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described below. The notice shall explain the reasons for the ISO's determination of the Material Adverse Change. After providing notice, the ISO may take one or more of the following actions: (i) require that, within two Business Days of receipt of the notice of Material Adverse Change, the Market Participant or Non-Market Participant Transmission Customer provide one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy and/or an additional amount of financial assurance in one of the forms of financial assurance described in Section X of the ISO New England Financial Assurance Policy; (ii) require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets; or (iii) require that the Market Participant or Non-Market Participant Transmission Customer take other measures to restore the ISO's confidence in its ability to safely transact in the New England Markets. Any additional amount of financial assurance required as a result of a Material Adverse Change shall be sufficient, as reasonably determined by the ISO, to cover the Market Participant's or Non-Market Participant Transmission Customer's potential settled and unsettled liability or obligation, provided, however, that if the additional amount of financial assurance required as a result of a Material Adverse Change is equal to or greater than $25 million, then the Chief Financial Officer shall first consult, to the extent practicable, with the ISO's Chief Executive Officer, Chief Operating Officer, and General Counsel. If the Market Participant or Non-Market Participant Transmission Customer fails to comply with any of the requirements imposed as a result of a Material Adverse Change, then the ISO may initiate termination proceedings against the Market Participant or Non-Market Participant Transmission Customer.

B. Weekly Payments

A Market Participant or Non-Market Participant Transmission Customer may request that, in lieu of providing the entire amount of one of the financial assurances set forth above to satisfy its Financial Assurance Requirement, a weekly billing schedule be implemented for its Non-Hourly Charges and its Transmission Charges. The ISO may, in its discretion, agree to such a request; provided, however, that any weekly billing arrangement for Non-Hourly Charges and Transmission Charges will terminate no more than six (6) months after the date on which such arrangement begins unless the Market Participant or Non-Market Participant Transmission Customer requests an extension of such arrangement and demonstrates to the ISO's satisfaction in its sole discretion that the termination of such arrangement and compliance with the other provisions of the ISO New England Financial Assurance Policy (including providing the full amount of its Financial Assurance Requirement) will impose a substantial hardship on the Market Participant or Non-Market Participant Transmission Customer. Such demonstration of a substantial hardship shall be made every six (6) months after the initial demonstration, and a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges will be terminated if it fails to demonstrate to the ISO's satisfaction in its sole discretion at any such six (6) month interval that compliance with the other provisions of the ISO New England Financial Assurance Policy will impose a substantial hardship on it. If the ISO agrees to implement a weekly billing schedule for Non-Hourly Charges and Transmission Charges for a Market Participant or Non-Market Participant Transmission Customer, the Market Participant or Non-Market Participant Transmission Customer shall be billed weekly for such Non-Hourly Charges and Transmission Charges in accordance with the ISO New England Billing Policy. The Market Participant or Non-Market Participant Transmission Customer shall pay with respect to each weekly Invoice for Non-Hourly Charges and Transmission Charges an administrative fee, determined by the ISO, to reimburse the ISO for the costs it incurs as a result of that Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement.

If a weekly billing schedule is implemented for a Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges under this Section XI.B, the Market Participant or Non-Market Participant Transmission Customer may be required to provide the full amount of its Financial Assurance Requirement at any time if the Market Participant or Non-Market Participant

Transmission Customer fails to pay when due any weekly Invoice. In addition, upon the termination of a Market Participant's or Non-Market Participant Transmission Customer's weekly billing arrangement for Non-Hourly Charges and Transmission Charges, the Market Participant or Non-Market Participant Transmission Customer shall either satisfy the applicable rating requirements set forth herein, satisfy the Credit Threshold, or provide the full amount of one of the other forms of financial assurance set forth herein.

C. Use of Transaction Setoffs

In the event that a Market Participant or Non-Market Participant Transmission Customer has failed to satisfy its Financial Assurance Requirement hereunder, the ISO may retain payments due to such Market Participant or Non-Market Participant Transmission Customer, up to the amount of such Market Participant's or Non-Market Participant Transmission Customer's unsatisfied Financial Assurance Requirement, as a cash deposit securing such Market Participant's or Non-Market Participant Transmission Customer's obligations to the ISO, NEPOOL, the Market Participants, the PTOs and the Non-Market Participant Transmission Customers, provided, however, that a Market Participant or Non-Market Participant Transmission Customer will not be deemed to have satisfied its Financial Assurance Requirement under the ISO New England Financial Assurance Policy because the ISO is retaining amounts due to it hereunder unless such Market Participant or Non-Market Participant Transmission Customer has satisfied all of the requirements of Section X with respect to such amounts.

D. Reimbursement of Costs

Each Market Participant or Non-Market Participant Transmission Customer that fails to perform any of its obligations under the Tariff, including without limitation those arising under the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, shall reimburse the ISO, NEPOOL and each Market Participant, PTO and Non-Market Participant Transmission Customer for all of the fees, costs and expenses that they incur as a result of such failure.

E. Notification of Default

In the event that a Market Participant or Non-Market Participant Transmission Customer fails to comply with the ISO New England Financial Assurance Policy (a "Financial

Assurance Default"), such failure continues for at least two days and notice of that failure has not previously been given, the ISO may (but shall not be required to) notify such Market Participant or Non-Market Participant Transmission Customer in writing, electronically and by first class mail sent in each case to such Market Participant's or Non-Market Participant Transmission Customer's billing and credit contacts or such Market Participant's member or alternate member on the Participants Committee (it being understood that the ISO will use reasonable efforts to contact all three where applicable), of such Financial Assurance Default. Either simultaneously with the giving of the notice described in the preceding sentence or within two days thereafter (unless the Financial Assurance Default is cured during such period), the ISO shall notify each other member and alternate on the Participants Committee and each Market Participant's and Non-Market Participant Transmission Customer's billing and credit contacts of the identity of the Market Participant or Non-Market Participant Transmission Customer receiving such notice, whether such notice relates to a Financial Assurance Default, and the actions the ISO plans to take and/or has taken in response to such Financial Assurance Default. In addition to the notices provided for herein, the ISO will provide any additional information required under the ISO New England Information Policy.

F. Remedies Not Exclusive

No remedy for a Financial Assurance Default is or shall be deemed to be exclusive of any other available remedy or remedies. Each such remedy shall be distinct, separate and cumulative, shall not be deemed inconsistent with or in exclusion of any other available remedy, and shall be in addition to and separate and distinct from every other remedy. A Financial Assurance Default may result in suspension of the Market Participant or Non-Market Participant Transmission Customer or the commencement of termination proceedings by the ISO.

G. Inquiries and Contests

A Market Participant or Non-Market Participant Transmission Customer may request a written explanation of the ISO's determination of its Market Credit Limit, Transmission Credit Limit, Financial Assurance Requirement or Transmission Obligations, including any change thereto, by submitting that request in writing to the ISO's Credit Department, either by email at CreditDepartment@iso-ne.com or by facsimile at (413) 540-4569. That request must include the Market Participant's customer identification number, the name of the Market Participant or Non-Market Participant Transmission Customer and the specific information for which the Market Participant or Non-Market Participant Transmission Customer would like an explanation and must be submitted by the designated credit contact for that Market Participant or Non-Market Participant Transmission Customer as on file with the ISO. In addition, since Financial Assurance Requirements are updated at least daily, any request for an explanation relating to the calculation of, or a change in, a Financial Assurance Requirement must be submitted on the same day as that calculation or change. The ISO's response to any request under this Section XI.G shall include an explanation of how the applicable calculation or determination was performed using the formulas and criteria in the ISO New England Financial Assurance Policy. A Market Participant or Non-Market Participant Transmission Customer may contest any calculation or determination by the ISO under the ISO New England Financial Assurance Policy using the dispute resolution provisions of Section I.6 of the Tariff.

H. Forward Contract/Swap Agreement

All FTR transactions constitute "forward contracts" and/or "swap agreements" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"), and the ISO shall be deemed to be a "forward contract merchant" and/or "swap participant" within the meaning of the Bankruptcy Code for purposes of those FTR transactions. Pursuant to the ISO New England Financial Assurance Policy, the ISO Tariff and the Market Participant Service Agreement with each Market Participant, the ISO already has, and shall continue to have, the following rights (among other rights) in respect of a Market Participant default under those documents (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy): A) the right to terminate and/or liquidate any FTR transaction held by that Market Participant; B) the right to immediately proceed against any additional financial assurance provided by that Market Participant; C) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement or similar agreement against any amounts due and owing by that Market Participant pursuant to any forward contract, swap agreement or similar agreement, such arrangement to constitute a "master netting agreement" within the meaning of the Bankruptcy Code; and D) the right to suspend that Market Participant from entering into future transactions in the FTR system. For the avoidance of doubt, upon the commencement of a voluntary or involuntary proceeding for a Market Participant under the Bankruptcy Code, and without limiting any other rights of the ISO or obligations of any Market Participant under the Tariff (including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy) or any Market Participant Service Agreement, the ISO may exercise any of its rights against such Market Participant, including, without limitation 1) the right to terminate and/or liquidate any FTR transaction held by that Market Participant, 2) the right to immediately proceed against any additional financial assurance provided by that Market Participant, 3) the right to set off any obligations due and owing to that Market Participant pursuant to any forward contract, swap agreement and/or master netting agreement against any amounts due and owing by that Market Participant with respect to an FTR transaction including as a result of the actions taken by the ISO pursuant to 1) above, and 4) the right to suspend that Market Participant from entering into future transactions in the FTR system.

ATTACHMENT 1

SECURITY AGREEMENT

THIS SECURITY AGREEMENT (the "Security Agreement") is effective as of this [__] day of [_____________], 20[_], by and between [INSERT NAME], a [_____________], having its principal office and place of business at [__________________________] (the "Debtor"), and ISO New England Inc., a Delaware nonprofit corporation (the "Secured Party" and collectively with the Debtor, the "Parties").

WITNESSETH:

In consideration of the mutual promises and covenants herein contained, the Parties agree as follows:

1. Definitions.

   a. In this Security Agreement:

      i. "Code" shall mean the Uniform Commercial Code, as enacted in the State of Connecticut and as amended from time to time.

      ii. "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (d) the products and proceeds of each of the foregoing.

      iii. "ISO Financial Assurance Policy" shall mean the Financial Assurance Policy in the Tariff, as amended, supplemented or restated from time to time, including but not limited to the Financial Assurance Policy in Exhibit 1A to Section I of the Tariff.

iv. “Tariff” shall mean the ISO New England Inc. Transmission, Markets and Services Tariff, as filed with the Federal Energy Regulatory Commission, as amended, supplemented and/or restated from time to time.

v. “Obligations” shall mean any and all amounts due from Debtor from time to time under the Tariff.

vi. “Market Participants” shall have the meaning set forth in the Tariff.

b. Any capitalized term not defined herein that is defined in the Code shall have the meaning as defined in the Code.

2. Security Interest. To secure the payment of all Obligations of the Debtor, Debtor hereby grants and conveys to the Secured Party a security interest in the Collateral. The Debtor hereby irrevocably authorizes the Secured Party at any time and from time to time to file in any applicable filing office any initial financing statements and amendments thereto that provide any information required by part 5 of Article 9 of the Code for the sufficiency or filing office acceptance of any financing statement or amendment.

3. Debtor’s Covenants. The Debtor warrants, covenants and agrees with the Secured Party as follows:

a. The Debtor shall perform all of the Debtor’s obligations under this Security Agreement according to its terms.

b. The Debtor shall defend the title to the Collateral against any and all persons and against all claims.

c. The Debtor shall at any time and from time to time take such steps as the Secured Party may reasonably request to ensure the continued perfection and priority of the Secured Party’s security interest in the Collateral and the preservation of its rights therein.

d. The Debtor acknowledges and agrees that this Security Agreement grants, and is intended to grant, a security interest in the Collateral. If the Debtor is a corporation, limited liability company, limited partnership or other Registered Organization (as that term is defined in Article 9 of the Uniform Commercial Code as in effect in Connecticut) the Debtor shall, at its expense, furnish to Secured Party a certified copy of Debtor’s organization documents verifying its correct legal name or, at Secured Party’s election, shall permit the Secured Party to obtain such certified copy at Debtor’s expense. From time to time at Secured Party's election, the Secured Party may obtain a certified copy of Debtor's organization documents and a search of such Uniform Commercial Code filing offices, as it shall deem appropriate, at Debtor's expense, to verify Debtor's compliance with the terms of this Security Agreement.

e. The Debtor authorizes the Secured Party, if the Debtor fails to do so, to do all things required of the Debtor herein and charge all expenses incurred by the Secured Party to the Debtor together with interest thereon, which expenses and interest will be added to the Obligations.

4. Debtor's Representations and Warranties. The Debtor represents and warrants to the Secured Party as follows:

a. The exact legal name of the Debtor is as first stated above.

b. Except for the security interest of the Secured Party, Debtor is the owner of the Collateral free and clear of any encumbrance of any nature.

5. Non-Waiver. Waiver of or acquiescence in any default by the Debtor or failure of the Secured Party to insist upon strict performance by the Debtor of any warranties, covenants, or agreements in this Security Agreement shall not constitute a waiver of any subsequent or other default or failure. No failure to exercise or delay in exercising any right, power or remedy of the Secured Party under this Security Agreement shall operate as a waiver thereof, nor shall any partial exercise of any right, power or remedy preclude any other or further exercise thereof or the exercise of any other right, power or remedy. The failure of the Secured Party to insist upon the strict observance or performance of any provision of this Security Agreement shall not be construed as a waiver or relinquishment of such provision. The rights and remedies provided herein are cumulative and not exclusive of any other rights or remedies provided at law or in equity.

6. Events of Default. Any one of the following shall constitute an "Event of Default" hereunder by the Debtor:

a. Failure by the Debtor to comply with or perform any provision of this Security Agreement or to pay any Obligation; or

b. Any representation or warranty made or given by the Debtor in connection with this Security Agreement proves to be false or misleading in any material respect; or

c. Any part of the Collateral is attached, seized, subjected to a writ or distress warrant, or is levied upon, or comes within the possession of any receiver, trustee, custodian or assignee for the benefit of creditors.

7. Remedy upon the Occurrence of an Event of Default. Upon the occurrence of any Event of Default the Secured Party shall, immediately and without notice, be entitled to use, sell, or otherwise liquidate the Collateral to pay all Obligations owed by the Debtor.

8. Attorneys' Fees, etc. Upon the occurrence of any Event of Default, the Secured Party's reasonable attorneys' fees and the legal and other expenses for pursuing, receiving, taking, keeping, selling, and liquidating the Collateral and enforcing the Security Agreement shall be chargeable to the Debtor.

9. Other Rights.

a. In addition to all rights and remedies herein and otherwise available at law or in equity, upon the occurrence of an Event of Default, the Secured Party shall have such other rights and remedies as are set forth in the Tariff and ISO Financial Assurance Policy.

b. Notwithstanding the provisions of the ISO New England Information Policy, as amended, supplemented or restated from time to time (the "ISO New England Information Policy"), Debtor hereby (i) authorizes the Secured Party to disclose any information concerning Debtor to any court, agency or entity which is necessary or desirable, in the sole discretion of the Secured Party, to establish, maintain, perfect or secure the Secured Party's rights and interest in the Collateral (the "Debtor Information"); and (ii) waives any rights it may have under the ISO New England Information Policy to prevent, impair or limit the Secured Party from disclosing such information concerning the Debtor.

10. PRE-JUDGMENT REMEDY. DEBTOR ACKNOWLEDGES THAT THIS SECURITY AGREEMENT AND THE UNDERLYING TRANSACTIONS GIVING RISE HERETO CONSTITUTE COMMERCIAL BUSINESS TRANSACTED WITHIN THE STATE OF CONNECTICUT. IN THE EVENT OF ANY LEGAL ACTION BETWEEN DEBTOR AND

THE SECURED PARTY HEREUNDER, DEBTOR HEREBY EXPRESSLY WAIVES ANY RIGHTS WITH REGARD TO NOTICE, PRIOR HEARING AND ANY OTHER RIGHTS IT MAY HAVE UNDER THE CONNECTICUT GENERAL STATUTES, CHAPTER 903a, AS NOW CONSTITUTED OR HEREAFTER AMENDED, OR OTHER STATUTE OR STATUTES, STATE OR FEDERAL, AFFECTING PREJUDGMENT REMEDIES, AND THE SECURED PARTY MAY INVOKE ANY PREJUDGMENT REMEDY AVAILABLE TO IT, INCLUDING, BUT NOT LIMITED TO, GARNISHMENT, ATTACHMENT, FOREIGN ATTACHMENT AND REPLEVIN, WITH RESPECT TO ANY TANGIBLE OR INTANGIBLE PROPERTY (WHETHER REAL OR PERSONAL) OF DEBTOR TO ENFORCE THE PROVISIONS OF THIS SECURITY AGREEMENT, WITHOUT GIVING DEBTOR ANY NOTICE OR OPPORTUNITY FOR A HEARING.

11. WAIVER OF JURY TRIAL. THE DEBTOR AND THE SECURED PARTY HEREBY EACH KNOWINGLY, VOLUNTARILY AND IRREVOCABLY WAIVES THE RIGHT TO TRIAL BY JURY IN ANY ACTION, DEFENSE, COUNTERCLAIM, CROSSCLAIM AND/OR ANY FORM OF PROCEEDING BROUGHT IN CONNECTION WITH THIS SECURITY AGREEMENT OR RELATING TO ANY OBLIGATIONS SECURED HEREBY.

12. Additional Waivers. Demand, presentment, protest and notice of nonpayment are hereby waived by Debtor. Debtor also waives the benefit of all valuation, appraisement and exemption laws.

13. Binding Effect. The terms, warranties and agreements herein contained shall bind and inure to the benefit of the respective Parties hereto, and their respective legal representatives, successors and assigns.

14. Assignment. The Secured Party may, upon notice to the Debtor, assign without limitation its security interest in the Collateral.

15. Amendment. This Security Agreement may not be altered or amended except by an agreement in writing signed by the Parties.

16. Term.

a. This Security Agreement shall continue in full force and effect until all Obligations owed by the Debtor have been paid in full.

b. No termination of this Security Agreement shall in any way affect or impair the rights and liabilities of the Parties hereto relating to any transaction or events prior to such termination date, or to the Collateral in which the Secured Party has a security interest, and all agreements, warranties and representations of the Debtor shall survive such termination.

17. Choice of Law. The laws of the State of Connecticut shall govern the rights and duties of the Parties herein contained without giving effect to any conflict-of-law principles.

IN WITNESS WHEREOF, the Parties have signed and sealed this Security Agreement as of the day and year first above written.

[INSERT NAME]

By: __________________________

Name:

Title:

ISO NEW ENGLAND INC.

By:__________________________

Name:

Title:

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ ______.00 (UNITED STATES DOLLARS ____________ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

____

____

____

A DRAWING CERTIFICATE SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF PRESENTATION CONTAINING THE FOLLOWING STATEMENT:

"THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_______________."

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _________ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. ___________ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY

DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES ("ISP98") OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE "ISP"), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE

ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE WHEN ACTUALLY RECEIVED BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_____________________________ _____________________________

[signature] [signature]

ATTACHMENT 3

ISO NEW ENGLAND MINIMUM CRITERIA FOR MARKET PARTICIPATION OFFICER CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the minimum criteria for market participation requirements set forth in Sections II.A.2 and II.A.3 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity has established or contracted for written policies, procedures, and controls applicable to participation in the New England Markets, approved by Certifying Entity’s independent risk management function[1], which provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Certifying Entity is exposed, including, but not limited to, credit risk, liquidity risk, concentration risk, default risk, operation risk, and market risk.

2. Certifying Entity has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets.

3. Certifying Entity has appropriate operating procedures and technical abilities to promptly and effectively respond to all ISO New England communications and directions.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s minimum criteria for market participation requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____

(Signature)

Print Name:________________________________

Title: ____________________________________

Date: ____________________________________

[1] As used in this certification, a Certifying Entity’s “independent risk management function” can include appropriate corporate persons or bodies that are independent of the Certifying Entity’s trading functions, such as a risk management committee, a risk officer, a Certifying Entity’s board or board committee, or a board or committee of the Certifying Entity’s parent company.

ATTACHMENT 4

ISO NEW ENGLAND ADDITIONAL ELIGIBILITY REQUIREMENTS

CERTIFICATION FORM

Certifying Entity:	

I,____, a duly authorized Senior Officer of

____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the additional eligibility requirements set forth in Section II.A.5 of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows:

1. Certifying Entity is now and in good faith will seek to remain (check applicable box(es)):

   □ an “appropriate person,” as defined in section(s) [   ] of the Commodity Exchange Act (7 U.S.C. § 1 *et seq*.) (specify which section(s) of Commodity Exchange Act sections 4(c)(3)(A) through (J) apply)) (if Certifying Entity is relying on section 4(c)(3)(F), it shall accompany this certification with supporting documentation reasonably acceptable to the ISO, provided that letters of credit shall be in the form of Attachment 2 to the ISO New England Financial Assurance Policy and shall be in an amount equal to the difference between five million dollars and the Certifying Entity’s total assets. Any such supporting documentation shall serve to establish eligibility under this Section II.A.5 and shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy);

   □ an “eligible contract participant,” as defined in section 1a(18)(A) of the Commodity Exchange Act and in 17 CFR § 1.3(m); or

   ☐ a “person who actively participates in the generation, transmission, or distribution of electric energy,” as defined in the Final Order of the Commodity Futures Trading Commission published at 78 FR 19880 (April 2, 2013).

2. If at any time Certifying Entity no longer satisfies the criteria in paragraph 1 above, Certifying Entity will immediately notify ISO New England in writing and will immediately cease all participation in the New England Markets.

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s additional eligibility requirements and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____

(Signature)

Print Name:__________________________________

Title: ______________________________________

Date: ______________________________________

ATTACHMENT 5

ISO NEW ENGLAND CERTIFICATE REGARDING CHANGES TO SUBMITTED RISK MANAGEMENT POLICIES FOR FTR PARTICIPATION

Certifying Entity:	

I,____, a duly authorized Senior Officer of ____(“Certifying Entity”), understanding that ISO New England Inc. is relying on this certification as evidence that Certifying Entity meets the annual certification requirement for FTR market participation regarding its risk management policies, procedures, and controls set forth in Section II.A.2(b) of the ISO New England Financial Assurance Policy (Exhibit IA to Section I of the ISO New England Inc. Transmission, Markets and Services Tariff) (the “Policy”), hereby certify that I have full authority to bind Certifying Entity and further certify as follows (check applicable box):

1. □ There have been no changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market.

   OR

2. □ There have been changes to the previously submitted written risk management policies, procedures, and controls (and any supporting documentation, if applicable) applicable to the Certifying Entity’s participation in the FTR market and such changes are clearly identified and attached hereto.*

I acknowledge that I have read and understand the provisions of the Policy, including those provisions describing ISO New England’s risk management policy requirements for FTR market participants and the remedies available to ISO New England in the event of a customer or applicant not satisfying those requirements. I acknowledge that the information provided herein true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission.

____

(Signature)

Print Name:_________________________________

Title: ____

Date: ____

*	As used in this certificate, "clearly identified" changes may include a redline comparing the current written risk management policies, procedures, and controls and the previously submitted written risk management policies, procedures, and controls; or resubmission of the written risk management policies, procedures, and controls with a bulleted list of all changes, including section and/or page numbers.

ATTACHMENT 6

MINIMUM CRITERIA FOR MARKET PARTICIPATION

INFORMATION DISCLOSURE FORM

Date: ____

Prepared by: ____

Customer/Applicant:[1] ____

I, _________________________, a duly authorized Senior Officer of ______________ ("Certifying Entity"), understanding that ISO New England Inc. ("ISO") is relying on this certification provided pursuant to Financial Assurance Policy Section II.A.1(a), hereby certify that I have full authority to bind Certifying Entity and further certify on behalf of Certifying Entity that the information contained herein is true, complete, and correct and is not misleading or incomplete for any reason, including by reason of omission:

1. List of all Principals.[2] Please discuss each Principal's relationship with the Certifying Entity and describe each Principal's previous experience related to participation in North American wholesale or retail energy markets or trading exchanges:

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[1] Customer and Applicant are each defined in Section II.A of the ISO New England Financial Assurance Policy, Exhibit 1A to Section 1 of the ISO Transmission, Markets, and Services Tariff ("Tariff"). Capitalized terms used but not otherwise defined herein shall have the meaning given to them in the Tariff.

[2] 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 ("FERC"), the Securities and Exchange Commission ("SEC"), the Commodity Futures Trading Commission ("CFTC"), any exchange monitored by the National Futures Association ("NFA"), 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.

2. List all material litigation (criminal or civil) against Certifying Entity or any of the Certifying Entity's Principals, Personnel,[1] or Predecessors,[2] arising out of participation in any wholesale or retail energy market (domestic or international) or trading exchanges in the past ten (10) years: *(Enter N/A if not applicable)*
3. List all sanctions issued against or imposed upon Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges where such sanctions were either imposed in the past ten (10) years or, if imposed prior to that, are still in effect. List all known material ongoing investigations regarding Certifying Entity, Certifying Entity's Principals, Personnel, or Predecessors, imposed by the FERC, the SEC, the CFTC, any exchange monitored by the NFA, or any entity responsible for regulating activity in any wholesale or retail energy market (domestic or international) or trading exchanges:
(Enter N/A if not applicable)

4. Provide a summary of any bankruptcy, dissolution, merger, or acquisition of Certifying Entity in the past ten (10) years (include date, jurisdiction, and other relevant details):
(Enter N/A if not applicable)

5. List all wholesale or retail energy market-related operations in North America where Certifying Entity is currently participating, or, in the past five (5) years, has previously participated other than in the New England Markets (e.g., PJM - FTRs):
(Enter N/A if not applicable)

6. Describe if Certifying Entity or any of Certifying Entity's Principals, Personnel, or any Predecessor of the foregoing ever had its participation or membership in any independent system operator or regional transmission organization (domestic or international) terminated, its registration/membership application denied, or is subject to an existing uncured suspension from participating in the markets of any independent system operator or regional transmission organization (domestic or international), each in the past five (5) years.
(Enter N/A if not applicable)

If you are currently an active participant and this is your annual submission you do not have to complete Question 7 and can skip to the signature block below. If you are in the process of applying for membership with the ISO you are required to answer the additional questions listed below.

7. Describe how Certifying Entity plans to fund its operations, including persons or entities providing financing and such person(s)' or entity(ies)' relationship to the Certifying Entity. Include any relationships that may impact Certifying Entity's ability to (a) comply with the time frames to post

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[1] Personnel means any person, current or former, responsible for decision making regarding Certifying Entity's transaction of business in the New England Markets, including, without limitation, decisions regarding risk management and trading, or any person, current or former, with access to enter transactions into ISO systems. Disclosures regarding former Personnel shall only be required for when such Personnel was employed by Certifying Entity.

[4] Predecessor shall mean any person or entity whose liabilities, including liabilities arising under the Tariff, have or may have been retained or assumed by Certifying Entity, either contractually, by operation of law or considering all relevant factors, including the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base.

financial assurance and/or pay invoices or other amounts owed to the ISO, each as required by the Tariff; or (b) provide a first priority perfected security interest in required financial assurance to the ISO:

Certifying Entity: ______________________________

By: ______________________________
(Signature)

Print Name: ______________________________

Title: ______________________________

Date: ______________________________

** To satisfy the disclosure requirements above, a Certifying Entity may attach additional materials and may provide the ISO with filings made to the SEC or other similar regulatory agencies that include substantially similar information to that required above, provided that Certifying Entity clearly indicates where the specific information is located in those filings.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

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EXHIBIT ID ISO NEW ENGLAND BILLING POLICY

SECTION 1 – OVERVIEW

Section 1.1 – Scope. The objective of this ISO New England Billing Policy is to define the billing and payment procedures to be utilized in administering charges and payments due under the Transmission, Markets and Services Tariff and the ISO Participants Agreement, in each case as amended, modified, supplemented and restated from time to time (collectively, the "Governing Documents"). Capitalized terms used but not defined in the ISO New England Billing Policy shall have the meanings specified in Section I. The ISO New England Billing Policy applies to the ISO, the Market Participants, Non-Market Participant Transmission Customers, PTOs, and Market Participants that transact only in the FTR Auction ("FTR-Only Customers") (referred to herein collectively as the "Covered Entities" and individually as a "Covered Entity") for billing and payments procedures for amounts due under the Governing Documents, including without limitation those procedures related to the New England Markets. As reflected and specified in Section 3 hereof, the ISO's obligation to make Payments (as defined below) is contingent on its receipt of sufficient aggregate Charges (as defined below) (or in cases of defaults in Covered Entities' payments of Charges, on the ISO's drawdowns under the ISO New England Financial Assurance Policy or recovery using the mechanisms specified in Section 3, 4 and 5 hereof).

Section 1.2 – Financial Transaction Conventions. The following conventions have been adopted in defining sums of money to be paid or received under the ISO New England Billing Policy:

a) The term "Charge" refers to a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

b) The term "Payment" refers to a sum of money due to a Covered Entity from the ISO. Amounts due to and from the ISO include amounts collected and paid by the ISO as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

c) Where a Covered Entity's total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an "Invoice" for the net Charge owed by such Covered Entity.

d) Where a Covered Entity's total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a "Remittance Advice" for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as "Statements."

Section 1.3 – General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases, Net Commitment Period Compensation, and daily Forward Capacity Market charges and payments ("Daily FCM Charges") (all such charges and payments described in this clause (i) being referred to collectively as the "Hourly Charges"); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the monthly Forward Capacity Market (exclusive of settlements included in the Hourly Charges) and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as ("Non-Hourly Charges" and, together with Hourly Charges, as "ISO Charges"), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the "ISO New England Financial Assurance Policy"); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as "Transmission Charges"). There are two major steps in the billing process:

a) *Statement Issuance*. The ISO will issue an Invoice or Remittance Advice showing the net amounts due from or owed to a Covered Entity. This Statement is determined from the preliminary statements of the New England Markets, applicable the ISO Charges and/or Transmission Charges due under the Governing Documents (including amounts due under the ISO New England Financial Assurance Policy), as well as applicable adjustments. Prior to January 1 of any calendar year, the ISO will post or make available a list of the dates in the new calendar year on which Statements will be issued, due and paid. Billing and payment holidays will be the same as the ISO's settlement holidays, as listed on the ISO's website from time to time.

b) *Electronic Funds Transfer ("EFT").* EFTs related to Invoices and Remittance Advices are performed in a two-step process, as described below, in which all Invoices are paid first and all Remittance Advices are paid later.

Section 1.4 – Special Billings. In addition to the regular billing process described above, the ISO will issue special, extraordinary Statements as and when required under the Governing Documents or in order to adjust for special circumstances. Such Statements shall be payable in accordance with the instructions set forth therein.

Section 1.5 – Conflicts with Governing Documents. Except as set forth herein, to the extent any provision hereof conflicts with any provision of any Governing Document, the provision in the Governing Document shall govern.

SECTION 2 - TIMING AND CONTENT OF STATEMENTS.

Section 2.1 – Statements for Hourly Charges. On each Monday and each Wednesday or on the following Business Day if such Monday or Wednesday is not a Business Day, the ISO shall provide electronically to each Covered Entity a Statement showing all complete-day settlement amounts for each of the Hourly Charges incurred and not reflected on a previously issued Statement. Each such Statement will cover only days with complete settled data. Accordingly, some Statements may have fewer days of settled data for certain Hourly Charges if fewer days have been settled for those Hourly Charges on the morning of the day that such Statements are issued; a following Statement may have more days of settled data for those Hourly Charges when it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 – Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 – Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 – Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

c) *ISO Self-Funding Charges.* The Charges owed by the Covered Entity under Section IV of the Transmission, Markets and Services Tariff, categorized by the section or schedule under which such Charges arise.

d) *Markets Charges and Payments.* The Hourly Charges owed by and the Payments for Hourly Charges owed to the Covered Entity as a result of transactions in each of the New England Markets administered by the ISO under Section III of the Transmission, Markets and Services Tariff.

e) *Monthly Forward Capacity Market Charges and Payments.* The Non-Hourly Charges owed by and the Payments for Non-Hourly Charges owed to the Covered Entity as a result of Capacity Performance Payments and other transactions in the Forward Capacity Market.

f) *Participant Expenses*. As defined in the Participants Agreement, the Covered Entity's share of costs and expenses that are incurred pursuant to authorization of the Participants Committee and are not considered costs and expenses of ISO.

g) [Reserved for Future Use]

h) *Other Amounts due under the Participants Agreement.* The Charges owed by or the Payments owed to the Covered Entity under the Participants Agreement to the extent that those amounts are not included in items (b)-(g) above.

i) *Other Non-Hourly Charges, Payments or Adjustments*. Any other Non-Hourly Charges, Payments for Non-Hourly Charges, or adjustments owed by or to the Covered Entity that are not included in items (b)-(h) above. These items may be due to retroactive billing adjustments, late payment fees, penalties or other items collectible under the Governing Documents.

j) *Billing Periods*. The billing period (from and to dates) covered for each line item on the Statement. The billing periods for the various line items are not necessarily the same because of differences in timing of settlements and because of retroactive adjustments.

k) *Payment Due Date and Time.* If the Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO.

l) *Wire Transfer Instructions*. Details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which ISO Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for ISO Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.5 – Monthly Statements for Transmission Charges. On the same date when each Monthly Statement is issued, the ISO shall provide electronically to each Covered Entity owing or owed any Transmission Charges for the preceding month a Statement (which may be combined with that Monthly Statement) showing all of the Transmission Charges for that Covered Entity for that preceding month (hereinafter sometimes referred to as a "Transmission Statement"). Any resettlements of Transmission Charges will also be included on the Transmission Statement. Each Transmission Statement will also include: (i) the billing month covered by the Transmission Statement; (ii) if the Transmission Statement is an Invoice, the date and time on which the net amount due is to be received by the ISO; and (iii) details including the account number, bank name, routing number and electronic transfer instructions which, in the case of an Invoice, will be for the ISO account to which Transmission Charges owed by the Covered Entity are to be paid or, in the case of a Remittance Advice, will be for the Covered Entity's account to which the ISO shall remit Payments for Transmission Charges owed to that Covered Entity (as previously provided to the ISO by such Covered Entity).

Section 2.6 – Certain Subsequent Adjustments to Previously Issued Statements.

a) *Adjustments Requested by Covered Entities*. Covered Entities supplying Regional Network Load and other input data to the ISO for use by the ISO in developing Statements shall use reasonable care to assure that the data supplied is complete and accurate. Should a Covered Entity supplying input data subsequently determine that the data supplied was incorrect, that Covered Entity shall notify the ISO promptly of the error and submit corrected data as soon as practicable. All errors in input data for a calendar month shall be corrected in one submission. If the error is detected and corrected data is provided within the time frames set forth below, the ISO will issue corrected Statements to reflect the newly supplied data.

Type of Adjustment	**Corrected Data Must be Submitted By**
Adjustments to Monthly Regional Network Load Submissions	20th day of the fourth (4th) month after the Regional Network Load Month
Adjustments to Annual Revenue Requirements Submissions	Annually during the rate development process, which is administered by the PTO Working Group
Adjustments to Annual Transmission, Markets and Services Tariff Section II, Schedule I Submissions	Annually during the rate development process, which is administered by the PTO Working Group

If the data correction is not submitted within the applicable time frame set forth above, the obligation of the ISO to issue corrected Statements reflecting that adjustment shall be as set forth in a written re-billing protocol, developed in consultation with the NEPOOL Budget and Finance Subcommittee, and as may be amended from time to time in consultation with the NEPOOL Budget and Finance Subcommittee, and posted on the ISO website. The re-billing protocol shall provide, for each category of adjustment listed above, whether and to what extent the adjustment shall be prospective or retroactive and the timing of the adjustment. If the corrected data is not submitted within the applicable time frame, the ISO may assess each Covered Entity submitting corrected data on an untimely basis its costs in generating and issuing the corrected Statement. The written re-billing protocol shall include a fee schedule for this purpose.

b) *Adjustments Triggered by ISO Audit*. The ISO will review the results of internal and outsourced audits with the PTO Administrative Committee and the Participants Committee or its delegee. The reasonable costs to the ISO of the re-billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 – PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 – Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two

Business Days prior to the Invoice Date. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4

(for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity's financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity's financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 – <u>ISO Payment of Remittance Advice Amounts</u>. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO issues such Remittance Advice by 11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -<u>Payment Default for ISO Charges</u>. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts due with respect to the Shortfall Funding Arrangement. NEPOOL GIS API Fees shall only be paid to the NEPOOL GIS Administrator to the extent that each Covered Entity or NEPOOL Participant owing such NEPOOL GIS API Fees has paid the full amount of all ISO Charges due on the Statement on which such NEPOOL GIS API Fees appear.

b) *Use of Set-Offs.* The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy against a defaulting Covered Entity with respect to ISO Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

c) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (b) above is insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

d) *Action Against a Defaulting Party.* If and to the extent that the procedures described in clauses (b) and (c) above are insufficient to effect payment of the Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel.

Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

e) *Late Payment Account.* If and to the extent that the procedures described in clauses (b), (c) and (d) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Default Amount, to the extent that such amount is available in the Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Late Payment Account on any date is insufficient to pay all Unsecured Default Amounts and Uncovered Default Amounts (each as defined below) on that date, the amount in the Late Payment Account shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts on or total Unsecured Default Amounts outstanding. Amounts withdrawn from the Late Payment Account and applied toward any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that such Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Default Amount allocated to them under clauses (h), (i) and (j) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Default Amount, interest and/or late charges shall be deposited into the Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

f) *Payment Default Shortfall Fund.* To the extent that the procedures described in clauses (b), (c), (d) and (e) above are insufficient to effect payment of the Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Default Amount and shall apply such amount to the shortfall in Payments resulting from the Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Default Amount. If and to the extent that a Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Default Amount and/or late charges with respect to such a Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

g) *Congestion Revenue Fund*. If during any billing period congestion payments exceed congestion charges under Manual 28 (hereinafter a "Congestion Shortfall"), such that there is a shortfall in the total settlement for that week due to congestion, the ISO will draw from the Congestion Revenue Fund established and funded under Manual 28 to make up for the shortfall. To the extent there are insufficient funds in the Congestion Revenue Fund to cover that Congestion Shortfall, the ISO will recover the uncovered Congestion Shortfall pursuant to the allocation process set forth in Manual 28, Section 6. The ISO will true-up amounts drawn for Congestion Shortfalls on a monthly basis and reflect that true-up in the Statements reflecting Non-Hourly Charges.

h) Reduction of Payments and Increases in Charges for Unsecured Municipal Market Participants

(i) If and to the extent that (A) the defaulting Covered Entity is a Municipal Market Participant (as defined in the ISO New England Financial Assurance Policy) with a Market Credit Limit or a Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (an "Unsecured Municipal Market Participant") and (B) the procedures described in clauses (b), (c), (d), (e), (f) and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for ISO Charges for the billing period to which the payment default relates (the "Default Period"), pro rata based on the ISO

Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(h)(i) shall not exceed the defaulting Unsecured Municipal Market Participant's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Default Amount"). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Statements for ISO charges for the Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Municipal Market Participant that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an

Unsecured Municipal Market Participant with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Municipal Market Participant with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Municipal Default Amount under this clause (h)(ii). Each Unsecured Municipal Market Participant that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Municipal Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Unsecured Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Default Amount under this clause (h)(ii), up to the full amount of such Unsecured Municipal Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Default Amounts under this Section 3.3(h) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

i) *Reduction of Payments and Increases in Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity (x) is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and (y) has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy (each such Covered Entity being referred to herein as an "Unsecured Non-Municipal Covered Entity") and (B) the procedures described in clauses (b), (c), (d), (e), (f), and (g) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for ISO Charges for the applicable Default Period, pro rata based on the ISO Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for ISO Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.3(i)(i) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Market Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Default Amount"). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Unsecured Non-Municipal Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Default Amount under this clause (i)(ii). Each Unsecured Non-Municipal Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Default Amount remaining unpaid under this clause (i)(ii). As funds attributable to an Unsecured Non-Municipal Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Default Amount under this clause (i)(ii), up to the full amount of such Unsecured Non-Municipal Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Default Amounts under this Section 3.3(i) for any Default Period if, at the start of the calendar year in which the applicable Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Financial Assurance Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

j) *Reduction of Payments and Increase in Charges for Other Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Municipal Market Participant or an Unsecured Non-Municipal Covered Entity (referred to together herein as an "Unsecured Covered Entity") or the Default Amount exceeds the Unsecured Municipal Default Amount or the Unsecured Non-Municipal Default Amount (referred to together herein as the "Unsecured Default Amount") for that Covered Entity and (B) the procedures described in clauses (b), (c), (d), (e), (f), (g), and (h) or (i) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for ISO Charges in full (after payment of amounts due to the ISO, to NEPOOL for Participant Expenses, and to the NEPOOL GIS Administrator for amounts due to the NEPOOL GIS Administrator other than for NEPOOL GIS API Fees and after payment of any amounts due with respect to the Shortfall Funding Arrangement, in accordance with clause (a) above) on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for ISO Charges for that Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for ISO Charges by the close of banking business on the date such Payments are due (after giving effect to clause (h) or (i) above if applicable) (the amount of such reduction in Payments for ISO Charges after giving effect to clause (h) or (i) above (if applicable) is referred to herein as the "Uncovered Default Amount"). For the avoidance of doubt, the Uncovered Default Amount is equal to the Default Amount minus any Unsecured Default Amount. As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Statements being distributed, such funds, together with any interest and late charges collected on the applicable Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Default Amount remains unpaid to Covered Entities on the date that Statements are distributed to Covered Entities in the billing period immediately following the Default Period, the Uncovered Default Amount remaining unpaid shall be reallocated among all of the Covered Entities receiving Statements for ISO Charges for the Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Default Amount remaining unpaid, on the sum of (i) all ISO Charges due from such Covered Entity that are reflected on its Statement for the Default Period and (ii) all Payments for ISO Charges due to such Covered Entity that are reflected on its Statement for the Default Period, without giving any effect to the process of netting Charges against Payments on each Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of ISO Charges and no Payments on its Statement for the Default Period and a Covered Entity with $1,000 of ISO Charges and $1,000 of Payments for ISO Charges on its Statement for the Default Period would be allocated an equal share of the unpaid Uncovered Default Amount under this clause (j)(ii). Each Covered Entity that received a Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Default Period adjusted as necessary to reflect its obligation for the Uncovered Default Amount remaining unpaid under this clause (j)(ii). As funds attributable to an Uncovered Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Default Amount under this clause (j) (ii), up to the full amount of such Uncovered Default Amount allocated to each such Covered Entity, with interest thereon.

k) *Order of Settlement*. As amounts on Default Amounts are received by the ISO, the oldest outstanding ISO Charges will be settled first in the order of the creation of such debts.

l) Notwithstanding the other provisions of this Section 3.3, an unpaid amount shall not be considered a "Default Amount," and the ISO will not take any of the actions described in the suspension provisions of the ISO New England Financial Assurance Policy or in this Section 3.3 with respect to that unpaid amount, if the total unpaid amount is attributable to Qualification Process Cost Reimbursement Deposits (including any annual true-up of those amounts) and/or NEPOOL GIS API Fees. To the extent that a Covered Entity or a NEPOOL Participant pays only a part of an Invoice that includes a Charge for a Qualification Process Cost Reimbursement Deposit and/or a Charge for NEPOOL GIS API Fees, the unpaid amount shall first be allocated to the unpaid NEPOOL GIS API Fees, and then to that Qualification Process Cost Reimbursement Deposit, and other Charges on that Invoice will only be considered not to have been paid if the unpaid amount exceeds the amount of the Qualification Process Cost Reimbursement Deposit and any unpaid NEPOOL GIS API Fees. The sole consequence of a Covered Entity's or a NEPOOL Participant's failure to pay NEPOOL GIS API Fees, after application of any set-off rights against the Covered Entity or NEPOOL Participant and any financial assurance provided by that Covered Entity or NEPOOL Participant, shall be denial to that Covered Entity or NEPOOL Participant of access to any application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

Section 3.4 – Payment Default for Transmission Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of Transmission Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (the "Transmission Default Amount"), then the following procedures shall apply:

a) *Use of Set-Offs*. The ISO shall use any and all rights of set-off it has under the Governing Documents, including the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, against a defaulting Covered Entity with respect to Transmission Charges due to that Covered Entity to the extent necessary to pay the Default Amount, together with any interest accrued thereon and any late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, due from such Covered Entity.

b) *Enforcing the Security of a Defaulting Party*. If and to the extent that the procedure described in clause (a) above is insufficient to effect payment of the Transmission Default Amount and all interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall use the financial assurance(s) provided by the defaulting Covered Entity under the ISO New England Financial Assurance Policy to the extent necessary to pay the Transmission Default Amount and such interest and late charges. Any use of financial assurance(s) shall be undertaken in compliance with the ISO New England Financial Assurance Policy.

c) *Action Against a Defaulting Party*. If and to the extent that the procedures described in clauses (a) and (b) above are insufficient to effect payment of the Transmission Default Amount and all interest accrued theron and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy, the ISO shall take appropriate actions to recover the Transmission Default Amount and such accrued interest and late charges, which actions may include, without limitation, initiating proceedings in accordance with the appropriate dispute resolution mechanisms or actions with Covered Entities or before the Commission or a court of competent jurisdiction against the defaulting Covered Entity. Before initiating any such proceedings, the ISO shall consult with the Chair of the NEPOOL Budget and Finance Subcommittee or NEPOOL counsel. Any amounts incurred by the ISO or any Market Participant in connection with any such action or proceeding shall be paid by the defaulting Covered Entity.

d) *Transmission Late Payment Account*. If and to the extent that the procedures described in clauses (a), (b) and (c) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy) by the time the corresponding Payment to the Covered Entities is due, the ISO shall withdraw from the Transmission Late Payment Account, as that term is defined in Section 4 of the ISO New England Billing Policy, an amount equal to such unpaid Transmission Default Amount, to the extent that such amount is available in the Transmission Late Payment Account, and shall apply such amount to any shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Transmission Late Payment Account on any date is insufficient to pay all Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined below) on that date, the amount in the Transmission Late Payment Account shall first be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts withdrawn from the Transmission Late Payment Account and applied toward any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that such Transmission Default Amount, interest thereon and/or late charges with respect thereto are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the defaulting Covered Entity), such amounts shall first be used to pay Covered Entities for the amount of such Transmission Default Amount allocated to them under clause (f), (g) and (h) below, with interest thereon, and then, after all such amounts have been paid to Covered Entities, such Transmission Default Amount, interest and/or late charges shall be deposited into the Transmission Late Payment Account in accordance with Section 4 of the ISO New England Billing Policy.

e) *Payment Default Shortfall Fund* To the extent that the procedures described in clauses (a), (b), (c) and (d) above are insufficient to effect payment of the Transmission Default Amount (but not interest accrued thereon and late charges assessed under the Governing Documents, including the ISO New England Financial Assurance Policy), the ISO will draw on the Shortfall Funding Arrangement to the extent the Shortfall Funding Arrangement is available at the time, and to the extent the Shortfall Funding Arrangement is not available at the time, the ISO will withdraw from the Payment Default Shortfall Fund, an amount equal to such unpaid Transmission Default Amount and shall apply such amount to the shortfall in Payments resulting from the Transmission Default Amount not being paid. To the extent that the amount on deposit in the Payment Default Shortfall Fund on any date is insufficient to pay all Unsecured Default Amounts, Uncovered Default Amounts, Unsecured Transmission Default Amounts and Uncovered Transmission Default Amounts (each as defined herein) on that date (after applying all amounts in the Late Payment Account for defaults on ISO Charges and all amounts in the Transmission Late Payment Account for defaults on Transmission Charges on that date), the amount in the Payment Default Shortfall Fund on that date shall first be applied to Uncovered Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, then such amount shall be applied to Unsecured Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts and all Unsecured Default Amounts, then such amount shall be applied to Uncovered Transmission Default Amounts on that date and, once cash has been applied to all Uncovered Default Amounts, Unsecured Default Amounts and Uncovered Transmission Default Amounts, then such amount shall be applied to Unsecured Transmission Default Amounts on that date, in each case pro rata based on the total Uncovered Default Amounts, total Unsecured Default Amounts, total Uncovered Transmission Default Amounts or total Unsecured Transmission Default Amounts outstanding. Amounts drawn on the Shortfall Funding Arrangement and/or withdrawn from the Payment Default Shortfall Fund and applied to any shortfall resulting from the Transmission Default Amount shall not relieve the defaulting Covered Entity of its obligation to pay such Transmission Default Amount. If and to the extent that a Transmission Default Amount which is paid through a draw on the Shortfall Funding Arrangement and/or through a withdrawal from the Payment Default Shortfall Fund, interest on such a Transmission Default Amount and/or late charges with respect to such a Transmission Default Amount are subsequently collected (including as a result of the use of a financial assurance under the ISO New England Financial Assurance Policy or through actions or proceedings against the Covered Entity), such amounts shall be paid to certain of the Covered Entities as set forth in Section 5.4 below.

f) *Reduction of Payments and Increases in Transmission Charges for Unsecured Municipal Market Participants.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Municipal Market Participant and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Municipal Market Participants owed monies for Transmission Charges for that billing period (the "Transmission Default Period"), pro rata based on the Transmission Charges owed to those Unsecured Municipal Market Participants, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Municipal Market Participants by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(f) shall not exceed the defaulting Unsecured Municipal Market Participant's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Municipal Transmission Default Amount"). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable

Unsecured Transmission Default Amount, shall be distributed pro rata to the Unsecured Municipal Market Participants that did not receive the full amount of their Payments as a result of such Unsecured Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Municipal Market Participants did not receive as a result of such Unsecured Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Municipal Transmission Default Amount remains unpaid to Unsecured Municipal Market Participants on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Municipal Market Participants receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Municipal Market Participant defaulting on its payment obligations), pro rata based, for each Unsecured Municipal Market Participant being allocated a share of the Unsecured Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Municipal Market Participant that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Municipal Market participant that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Municipal Market Participant with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Municipal Market Participant with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Municipal Transmission Default Amount under this clause (f)(ii). Each Unsecured Municipal Market Participant that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the

Unsecured Municipal Transmission Default Amount remaining unpaid under this clause (f)(ii). As funds attributable to an Unsecured Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Municipal Transmission Default Amount, shall be distributed to the Unsecured Municipal Market Participants pro rata based on their allocation of the Unsecured Municipal Transmission Default Amount under this clause (f)(ii), up to the full amount of such Unsecured Municipal Transmission Default Amount allocated to each such Unsecured Municipal Market Participant, with interest thereon.

(iii) An Unsecured Municipal Market Participant will not be allocated any Unsecured Municipal Transmission Default Amounts under this Section 3.4(f) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Municipal Market Participant provided the ISO with a written request to opt out of that allocation of Unsecured Municipal Transmission Default Amounts and that Unsecured Municipal Market Participant provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy at all times during that calendar year.

g) *Reduction of Payments and Increases in Transmission Charges for Unsecured Non-Municipal Covered Entities.*

(i) If and to the extent that (A) the defaulting Covered Entity is an Unsecured Non-Municipal Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), and (e) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to all Unsecured Non-Municipal Covered Entities owed monies for the applicable Transmission Default Period, pro rata based on the Transmission Charges owed to those Unsecured Non-Municipal Covered Entities, to the extent necessary to clear its accounts for Transmission Charges due to Unsecured Non-Municipal Covered Entities by the close of banking business on the date such Payments are due; provided, however, that the total amount of reduced Payments under this Section 3.4(g) shall not exceed the defaulting Unsecured Non-Municipal Covered Entity's Transmission Credit Limit under the ISO New England Financial Assurance Policy (such total amount of reduced Payments being referred to as the "Unsecured Non-Municipal Transmission Default Amount"). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed pro rata to the Unsecured Non-Municipal Covered Entities that did not receive the full amount of their Payments as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, up to the full amount that such Unsecured Non-Municipal Covered Entities did not receive as a result of such Unsecured Non-Municipal Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any Unsecured Non-Municipal Transmission Default Amount remains unpaid to Unsecured Non-Municipal Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Unsecured Non-Municipal Transmission Default Amount remaining unpaid shall be reallocated among all of the Unsecured Non-Municipal Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Unsecured Non-Municipal Covered Entity defaulting on its payment obligations), pro rata based, for each Unsecured Non-Municipal Covered Entity being allocated a share of the Unsecured Non-Municipal Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments for Transmission Charges due to such Unsecured Non-Municipal Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, an Unsecured Non-Municipal Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and an Unsecured Non-Municipal Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments for Transmission Charges on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii). Each Unsecured Non-Municipal Covered Entity that received a Transmission Statement for the Transmission Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Unsecured Non-Municipal Transmission Default Amount remaining unpaid under this clause (g)(ii). As funds attributable to an Unsecured Non-Municipal Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Unsecured Non-Municipal Transmission Default Amount, shall be distributed to the Unsecured Non-Municipal Covered Entities pro rata based on their allocation of the Unsecured Non-Municipal Transmission Default Amount under this clause (g)(ii), up to the full amount of such Unsecured Non-Municipal Transmission Default Amount allocated to each such Unsecured Non-Municipal Covered Entity, with interest thereon.

(iii) An Unsecured Non-Municipal Covered Entity will not be allocated any Unsecured Non-Municipal Transmission Default Amounts under this Section 3.4(g) for any Transmission Default Period if, at the start of the calendar year in which the applicable Transmission Default Period occurred, that Unsecured Non-Municipal Covered Entity provided the ISO with a written request to opt out of that allocation of Unsecured Non-Municipal Transmission Default Amounts and that Unsecured Non-Municipal Covered Entity provides the ISO with additional financial assurance in the full amount of all of its "Transmission Obligations" under the ISO New England Financial Assurance Policy all times during that calendar year.

h) *Reduction of Payments and Increases in Transmission Charges for Other Covered Entities*.

(i) If and to the extent that (A) the defaulting Covered Entity is not an Unsecured Covered Entity or the Transmission Default Amount for that Covered Entity exceeds the Unsecured Municipal Transmission Default Amount or the Unsecured Non-Municipal Transmission Default Amount (referred to together herein as the "Unsecured Transmission Default Amount") for that Covered Entity and (B) the procedures described in clauses (a), (b), (c), (d), (e) and (f) or (g) (if applicable) above do not yield sufficient funds to pay all Remittance Advice amounts for Transmission Charges in full on the date such Payments are due, the ISO shall reduce Payments to those Covered Entities owed monies for Transmission Charges for that Transmission Default Period, pro rata based on the amounts owed to all Covered Entities, to the extent necessary to clear its accounts for Transmission Charges by the close of banking business on the date such Payments are due (after giving effect to clauses (f) and (g) above if applicable) (the amount of such reduction in Payments for Transmission Charges after giving effect to clauses (f) and (g) above (if applicable) is referred to herein as the "Uncovered Transmission Default Amount"). For the avoidance of doubt, the Uncovered Transmission Default Amount is equal to the Transmission Default Amount minus any Unsecured Transmission Default Amount. As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurance provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) prior to the next billing period's Transmission Statements being distributed, such funds, together with any interest and late charges collected on the applicable Transmission Default Amount, shall be distributed pro rata to the Covered Entities that did not receive the full amount of their Payments as a result of such Uncovered Transmission Default Amount not being paid, up to the full amount that such Covered Entities did not receive as a result of such Uncovered Transmission Default Amount not being paid, with interest thereon.

(ii) To the extent that any amount of an Uncovered Transmission Default Amount remains unpaid to Covered Entities on the date that Transmission Statements are distributed to Covered Entities in the billing period immediately following the Transmission Default Period, the Uncovered Transmission Default Amount remaining unpaid shall be reallocated among all the Covered Entities receiving Transmission Statements for Transmission Charges for the Transmission Default Period (other than the Covered Entity defaulting on its payment obligations), pro rata based, for each Covered Entity being allocated a share of the Uncovered Transmission Default Amount remaining unpaid, on the sum of (i) all Transmission Charges due from such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period and (ii) all Payments due to such Covered Entity that are reflected on its Transmission Statement for the Transmission Default Period, without giving any effect to the process of netting Charges against Payments on each Transmission Statement that is the result of the ISO's single billing system. Thus, by way of example, a Covered Entity with $2,000 of Transmission Charges and no Payments on its Transmission Statement for the Transmission Default Period and a Covered Entity with $1,000 of Transmission Charges and $1,000 of Payments on its Transmission Statement for the Transmission Default Period would be allocated an equal share of the unpaid Uncovered Transmission Default Amount under this clause (h)(ii). Each Covered Entity that received a Transmission Statement for the Default Period shall have the amount of its Invoice or Remittance Advice in the billing period immediately following the Transmission Default Period adjusted as necessary to reflect its obligation for the Uncovered Transmission Default Amount remaining unpaid under this clause (h)(ii). As funds attributable to an Uncovered Transmission Default Amount are received by the ISO (including amounts received through financial assurances provided under the ISO New England Financial Assurance Policy or through actions or proceedings commenced against the defaulting Covered Entity) after such adjusted Transmission Statements are distributed, such funds, together with any interest and late charges collected on the applicable Uncovered Transmission Default Amount, shall be distributed to the Covered Entities pro rata based on their allocation of the Uncovered Transmission Default Amount under this clause (h)(ii), up to the full amount of such Uncovered Transmission Default Amount allocated to each such Covered Entity, with interest thereon.

i) Order of Settlement.

As amounts on Transmission Default Amounts are received by the ISO, the oldest outstanding Transmission Charges will be settled first in the order of the creation of such debts.

Section 3.5 -Enforcement of Payment Obligations Against Defaulting Covered Entities. Each Covered Entity that shared in any shortfall in payments under Section 3.3 or Section 3.4 shall have an independent right to seek and obtain payment and recovery of the amount of its share of such shortfall (the "Allocated Assessment") from the defaulting Covered Entity. Each Covered Entity consents to other Covered Entities' having this independent right. Any Covered Entity that recovers any portion of its Allocated Assessment from a defaulting Covered Entity shall promptly so notify the ISO, and such Covered Entity's share of any recovery of a shortfall in payments hereunder shall be reduced by the amount of its Allocated Assessment that it recovers on its own. In addition to any amounts in default, the defaulting Covered Entity shall be liable to the ISO and each other Covered Entity for all reasonable costs incurred in enforcing the defaulting Covered Entity's obligations.

Section 3.6 – Set-Off. The ISO shall apply any amount to which any defaulting Covered Entity is or will be entitled for ISO Charges or Transmission Charges toward the satisfaction of any of that defaulting Covered Entity's debts to NEPOOL or to the ISO for ISO Charges or Transmission Charges which are incurred under the Governing Documents, including the ISO New England Financial Assurance Policy; provided that amounts due for ISO Charges will first be applied to ISO Charges then, to the extent of any excess, to Transmission Charges, and amounts due for Transmission Charges will be first applied to Transmission Charges then, to the extent of any excess, to ISO Charges.

Section 3.7 – Notice and Suspension. Without limiting any of the other remedies described above, in the event that the ISO, in its reasonable opinion, believes that all or any part of any amount due to be paid by any Covered Entity for ISO Charges (other than NEPOOL GIS API Fees) or Transmission Charges will not be or has not been paid when due, the ISO (on its own behalf or on behalf of the Covered Entities) may (but shall not be required to) notify such Covered Entity in writing, electronically and by first class mail sent in each case to such Covered Entity's billing contact, of such payment default. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 10:00 a.m. Eastern Time on the Business Day immediately following the Business Day when such payment was originally due, the ISO shall notify such Market Participant, the NEPOOL Budget and Finance Subcommittee, all members and alternates of the Participants Committee, the New England governors and utility regulatory agencies and the credit and billing contacts for all Market Participants of (i) the identity of the Covered Entity receiving such notice, (ii) whether such notice relates to a payment default, (iii) whether the defaulting Covered Entity has a registered load asset, and (iv) the actions the ISO plans to take and/or has taken in response to such payment default. In addition, the ISO will provide any additional information with respect to such payment default as may be required under the ISO New England Information Policy. If a payment default (other than a payment default relating solely to NEPOOL GIS API Fees) is not cured by 8:30 a.m., Eastern Time, of the second Business Day after the date when such payment was originally due, the defaulting Covered Entity shall be suspended pursuant to the suspension provisions of the ISO New England Financial Assurance Policy (which will apply to the defaulting Covered Entity regardless of whether it is a "Municipal Market Participant" or a "Non-Municipal Market Participant" under the ISO New England Financial Assurance Policy). Such defaulting Covered Entity shall be suspended as described in the ISO New England Financial Assurance Policy until such payment default has been cured in full. If the ISO has issued a notice that a Covered Entity has defaulted on a payment obligation and that Covered Entity subsequently cures that payment default, such Covered Entity may request the ISO to issue a notice stating such fact; provided, however, that the ISO shall not be required to issue that notice unless, in its sole discretion, the ISO determines that such payment default has been cured and such Covered Entity has no other outstanding payment defaults.

If either (x) a Covered Entity is suspended from the New England Markets as a result of a payment default as described in this Section 3.7 as a result of a payment default involving ISO Charges or (y) a Covered Entity receives more than five notices of payment defaults with respect to ISO Charges in any rolling 12-month period, then such Covered Entity shall pay a $1,000 penalty for such suspension and for each notice after the fifth notice in a rolling 12-month period. All penalties paid under this paragraph shall be deposited in the Late Payment Account.

Section 3.8– Bankruptcy Filings. In the event any 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 (the "Bankruptcy Event") and the ISO is required to return any payments made by such Covered Entity to the bankruptcy court having jurisdiction over such Bankruptcy Event, the ISO may avail itself of any emergency funding provisions in the Transmission, Markets and Services Tariff to collect the amounts returned by the ISO.

Section 3.9 – Partial Payments of Combined Invoices. If ISO Charges and Transmission Charges are included on the same Invoice and the Covered Entity pays only a portion of the Charges included in that Invoice, then the ISO shall use monies received by it from that Covered Entity (i) first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager for the NEPOOL GIS before making any payments to any Covered Entities, then (ii) then to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees), (iii) then to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement, and (iv) then, to the extent of any remaining amounts received from that Covered Entity, those amounts will be allocated to the ISO Charges and Transmission Charges on that Invoice pro rata based on the total amount of each set of Charges on that Invoice, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees. Notwithstanding the foregoing, a partial payment of any Invoice shall be a payment default.

3.10 – Sharing of Financial Assurance. If the financial assurance(s) provided by a Covered Entity under the ISO New England Financial Assurance Policy are insufficient to effect payment of all ISO Charges and Transmission Charges that are due on the same date and which have not been paid by that Covered Entity, the ISO shall allocate the amounts available under those financial assurance(s) as follows:

i. first to pay all amounts due from that Covered Entity to the ISO under Section IV of the Transmission, Markets and Services Tariff, to NEPOOL for Participant Expenses, and to the ISO for acting as Project Manager of the NEPOOL GIS;

ii. second, to pay all amounts due for that Covered Entity's share, if any, of the amounts due to the NEPOOL GIS Administrator (other than NEPOOL GIS API Fees);

iii. third, to pay all amounts due from that Covered Entity with respect to the Shortfall Funding Arrangement;

iv. fourth, to the Covered Entity's Charges for FTR transactions, up to the FTR Financial Assurance Requirements calculated for that Covered Entity by the ISO on the last day of the billing period for which the payment default has occurred; and

v. fifth, to the remaining unpaid ISO Charges and the unpaid Transmission Charges owed by that Covered Entity pro rata based on the total amount of each set of Charges due, subject to Section 3.3(l) with respect to Charges for Qualification Process Cost Reimbursement Deposits and/or Charges for NEPOOL GIS API Fees.

Section 3.11 – Allocation of Payment Defaults to Other Groups. In some cases, the Default Amount or the Transmission Default Amount may exceed the amounts owed to the specified Covered Entities that are to receive less than the full Payments due to them pursuant to Section 3.3(h)(i), Section 3.3(i)(i), Section 3.4(f)(i) or Section 3.4(g)(i). In such an event, the ISO will reduce the Payments due to Covered Entities pursuant to Section 3.3(j)(i) (for ISO Charges) or Section 3.4(h)(i) (for Transmission Charges) to the extent necessary for the ISO to clear its accounts for ISO Charges or Transmission Charges by the close of banking business on the date the applicable Payments are due. Any amount allocated to Covered Entities under the preceding sentence will be invoiced to and collected from the appropriate Covered Entities under Section 3.3(h)(ii), Section 3.3(i)(ii), Section 3.4(f)(ii) or Section 3.4(g)(ii) in the billing period immediately following the billing period in which that allocation occurred.

Section 3.12 – Other Rights Against Defaulting Parties. Nothing set forth in the ISO New England Billing Policy shall nullify, restrict or otherwise limit the rights and remedies of the ISO, NEPOOL and the Covered Entities against a defaulting Covered Entity that are set forth in the Governing Documents, including the ISO New England Financial Assurance Policy or otherwise, including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Transmission Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant's history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

SECTION 5 – SHORTFALL FUNDING ARRANGEMENTS: PAYMENT DEFAULT SHORTFALL FUND

Section 5.1 – Purpose and Creation of the Shortfall Funding Arrangement and the Payment Default Shortfall Fund. The ISO, acting in consultation with the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor, will arrange separate financing (the "Shortfall Funding Arrangement") that can be used to make up any non-congestion related differences between ISO Charges received on Invoices and amounts due for ISO Charges in any week and as set forth in Sections 3.3 and 3.4. The Shortfall Funding Arrangement may be effected through third-party financing, through the creation of a special purpose funding entity, through Participant-provided funds or through some other arrangement agreed upon by the ISO, the NEPOOL Budget and Finance Subcommittee and NEPOOL's Independent Financial Advisor. If and to the extent that, at any time, the Shortfall Funding Arrangement is not available (because, solely for example, it has not been arranged, it does not have sufficient funds available, it has expired or it has been terminated prior to its maturity), the ISO shall create a Payment Default Shortfall Fund that will provide for such non-congestion related difference between ISO Charges received on Invoices and amounts due for ISO Charges in any week and for payments in accordance with Section 3.3 and 3.4. The Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund shall be in addition to and not a replacement for the Late Payment Account or the Transmission Late Payment Account described above.

Section 5.2 -Participant Rights with respect to a Participant Financial Payment Default Shortfall Fund. To the extent that the Payment Default Shortfall Fund is in existence at any time, each Participant funding the Payment Default Shortfall Fund at such time would retain title to its share of amounts in the Payment Default Shortfall Fund and any interest accrued on those amounts on a pro rata basis based on the funds in the Payment Default Shortfall Fund provided by it. Each Participant will receive a monthly report that will identify the amount of funds in the Payment Default Shortfall Fund that belong to that Participant and the amount of interest accrued thereon. As Participants withdraw from or otherwise terminate membership in the ISO, the ISO would pay to such Participants their share, if any, of the amounts in the Payment Default Shortfall Fund, with interest. To the extent that the balance in the Payment Default Shortfall Fund exceeds the Required Balance, the excess will be refunded to Participants on a quarterly basis pro rata based on their share of the funds in the Payment Default Shortfall Fund.

Section 5.3 – Available Amount of Shortfall Funding Arrangement; Initial Funding of the Payment Default Shortfall Fund. The available amount of the Shortfall Funding Arrangement, combined with any amount on deposit in the Payment Default Shortfall Fund, shall be equal to the amount of a hypothetical Invoice at the 97th percentile of the average amounts due on Invoices rendered to Market Participants over the six calendar months preceding the calculation or a lesser amount as set by the ISO from time to time in consultation with the NEPOOL Budget and Finance Subcommittee (the "Required Balance"), which amount shall be calculated and adjusted by the ISO on a quarterly basis. To the extent that on any Business Day immediately following the date on which Payments for Non-Hourly Charges are due, either the Shortfall Funding Arrangement has not been established or the available amount of the Shortfall Funding Arrangement is less than the Required Balance, the ISO shall establish the Payment Default Shortfall Fund, and the Participants shall be responsible for initially funding the Payment Default Shortfall Fund in an amount equal to the Required Balance less the available amount, if any, of the Shortfall Funding Arrangement on such date (the "Participant Required Balance"). The ISO, in consultation with NEPOOL's Independent Financial Advisor, shall notify the Market Participants promptly if they believe that the available amount of the Shortfall Funding Arrangement is not, or is reasonably likely not to be, at least equal to the Required Balance, and the ISO will endeavor to arrange a supplement to any existing Shortfall Funding Arrangement at least to the extent required to fund such shortfall. The Market Participant Required Balance shall initially be funded by the Market Participants pro rata in accordance with the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due over the three months immediately preceding the establishment of the Payment Default Shortfall Fund). A Participant's Payment Default Shortfall Fund payment obligation shall be identified as a separate line item on its Statements and Transmission Statements.

Section 5.4 Continued Shortfall Fund Funding Obligations; Payments on Shortfall Funding Arrangement.

(a) The ISO will reallocate the Market Participants' overall obligation with respect to the amounts in the Payment Default Shortfall Fund, if any, annually on each anniversary of the Effective Date in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on the Charges and Payment due in the preceding calendar year), with payments from and refunds to Market Participants that have underfunded or overfunded, respectively, the Payment Default Shortfall Fund based on that annual reallocation.

(b) If the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund (the "Total Available Amount") drops below 90 percent of the Required Balance at any time because of Market Participant terminations (but not because of draws on the Shortfall Funding Arrangement or the Payment Default Shortfall Fund or adjustments to the Required Balance), each Market Participant would be required to contribute a share of the funds needed to restore the Total Available Amount to the Required Balance. A Market Participant's pro rata share of that obligation would be determined in accordance with the methodology used for shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy (but based on Charges and Payments due for the three months immediately preceding the date of that funding).

(c) If (i) the ISO draws on the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund and the amount drawn, together with interest and fees thereon, is not replaced through payments on the payment default by the date on which the ISO next issues an Invoice that includes Non-Hourly Charges, or (ii) the Required Balance is increased as a result of quarterly adjustments, that next Invoice for Non-Hourly Charges will include a charge for Covered Entities necessary to restore the Total Available Amount to the Required Balance. That charge will be allocated among the Covered Entities according to the methodology used for the shortfall allocation process in Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy with respect to the specific payment default. If payments on a payment default are received after the amount drawn from the Shortfall Funding Arrangement and/or the Payment Default Shortfall Fund for that payment default has been refunded, the amount of the payment default so received shall be allocated and paid to the Covered Entities providing that funding according to the methodology of Section 3.3(j)(ii) and Section 3.4(h)(ii) of the ISO New England Billing Policy.

(d) In addition to the other obligations described in this Section 5.4, each Market Participant shall be charged a pro rata share of all interest, fees and other expenses incurred in connection with the Shortfall Funding Arrangement to the extent that such interest, fees and expenses are not paid by a Covered Entity with respect to a payment default. The pro rata allocation of fees and expenses described herein shall be made on the same basis as set forth in Section 5.4(c) above. A Market Participant's obligation with respect to the Shortfall Funding Arrangement shall be identified as a separate line item on its statements.

(e) Without limiting the generality of Section 3.3 and Section 3.4, to the extent that a Covered Entity fails to pay an Invoice, requiring a draw on the Shortfall Funding Arrangement, that Covered Entity shall be required to pay the amount of such draw, plus any interest accrued thereon and premium or other fees or expenses with respect thereto.

Section 5.5 -<u>Payment Default Shortfall Fund Account.</u> Funds collected as Market Participant contributions to the Payment Default Shortfall Fund shall be deposited by the ISO into a segregated interest-bearing account.

SECTION 6 -BILLING DISPUTE PROCEDURES.

Section 6.1 -<u>Requested Billing Adjustments Eligible for Resolution under Billing Dispute Procedures.</u> Any Covered Entity may dispute the amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice (a "Disputed Amount"). Such party (a "Disputing Party") shall seek to recover such Disputed Amount, including accrued interest, pursuant to this Section 6, by first submitting a request for billing adjustment to the ISO (a "Requested Billing Adjustment" or "RBA") in accordance with the procedures provided in this Section 6. A Disputing Party may seek resolution of a Requested Billing Adjustment under this Section 6 concerning any Disputed Amount resulting from the determination of a market clearing price or Transmission, Markets and Services Tariff rate by the ISO that allegedly either violates or is otherwise inconsistent with the Transmission, Markets and Services Tariff, or results from error by the ISO, and provided that a request for a correction of a Meter Data Error shall not be considered a Requested Billing Adjustment for purposes of the ISO New England Billing Policy, and requests for corrections of Meter Data Errors will be handled exclusively through the procedures set out in Market Rule 1. Notwithstanding the foregoing, a Requested Billing Adjustment must involve a requested change in an amount owed or believed to be owed in a Remittance Advice that is not covered by another alternative dispute resolution procedure under the Transmission, Markets and Services Tariff. Furthermore, a Requested Billing Adjustment must not involve Disputed Amounts paid on an Invoice for Non-Hourly Charges pursuant to the ISO New England Financial Assurance Policy, provided, however, that this provision shall not preclude a Disputing Party from submitting a Requested Billing Adjustment for a Disputed Amount on a fully paid monthly Invoice for Non-Hourly Charges which has been paid pursuant to an Invoice for Non-Hourly Charges in that month.

Section 6.2 -Effect of the ISO New England Billing Policy on Rights of Market Participant, PTO, or Non-Market Participant Transmission Customer with Respect to a Disputed Amount. Except as otherwise set forth in this Section 6.2, nothing in this Section 6 shall in any way abridge the right of any Covered Entity to seek legal or equitable relief under the Federal Power Act and/or any other applicable laws with respect to any Disputed Amount. Prior to commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction to resolve the dispute which is the subject of the Requested Billing Adjustment, the Disputing Party must first submit the Requested Billing Adjustment to the ISO for review pursuant to Section 6.3 of the ISO New England Billing Policy.

Section 6.3 – ISO Review of Requested Billing Adjustment.

Section 6.3.1 – Submission of Requested Billing Adjustment to the ISO; Required Contents of Requested Billing Adjustment. A Disputing Party shall submit a Requested Billing Adjustment in writing to Participant Support and Solutions at the ISO via its support system. A Requested Billing Adjustment will be deemed received once an acknowledgement and/or a case number has been assigned and transmitted to the Disputing Party. In its Requested Billing Adjustment, the Disputing Party must specify: (a) the Disputed Amount at issue, (b) the instance of alleged error at issue, including a statement detailing the specific provisions of all applicable governing documents that support the Requested Billing Adjustment, and (c) the specific person or persons to whom all communications to the Disputing Party regarding the Requested Billing Adjustment are to be addressed. A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

Section 6.3.2 – <u>Notice of ISO Review of Requested Billing Adjustment</u>. Within three Business Days of the receipt ISO Participant Support and Solutions by of a Requested Billing Adjustment, 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 Requested Billing Adjustment ("Notice of RBA"), including, subject to the protection of Confidential Information, the specifics of the Requested Billing Adjustment. The Notice of RBA shall identify a specific representative of the ISO to whom all communications regarding the Requested Billing Adjustment are to be sent.

Section 6.3.3 – <u>ISO Review of Requested Billing Adjustments.</u> The ISO shall complete its review of a Requested Billing Adjustment received pursuant to Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA. To the extent that either party makes such a request and both parties agree to such request, the ISO and Disputing Party may meet or otherwise confer during this period in an effort to resolve the Requested Billing Adjustment.

Section 6.3.4 – <u>Comment Period.</u> Any Covered Entity which desires to do so, or NEPOOL if it desires to do so, may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the Notice of RBA, written comments to the ISO with respect to the Requested Billing Adjustment. Any such comments are to be transmitted simultaneously to the Disputing Party. The Disputing Party may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the Notice of RBA. In determining the action it will take with respect to the Requested Billing Adjustment, the ISO shall consider the written response filed by the Disputing Party. The ISO may but is not required to consider any written comments that are filed by any other interested party.

Section 6.3.5 – <u>ISO Action on Requested Billing Adjustment</u>. The ISO shall provide to the Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee a written decision (the "RBA Decision") accepting or denying a Requested Billing Adjustment received pursuant to this Section 6.3 within twenty (20) Business Days of the date the ISO distributes the Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO. The

ISO shall provide written notice and a copy of each RBA Decision to each Covered Entity either eligible for reimbursement, denied reimbursement of a Disputed Amount or required to provide reimbursement of a Disputed Amount because of an RBA Decision (hereafter referred to as an "Affected Party" or the "Affected Parties") within five (5) Business Days of the date the RBA Decision is rendered. In providing such notice to any Affected Party required to provide reimbursement of a Disputed Amount, the ISO shall specify the amount to be reimbursed by such Affected Party and the calculations supporting the determination of such reimbursement amount. Subsequent to the provision of the written notice of the RBA Decision as set forth above, the ISO shall provide each Affected Party with respect to that RBA Decision a monthly report of the status of such RBA Decision within the dispute resolution process set forth in this Section 6, including a statement of the accounting treatment of the disputed amount owed by or to that Affected Party with respect to that RBA Decision in accordance with the most recent decision issued pursuant to Sections 6.3.6 or 6.4 of the ISO New England Billing Policy, whichever applies, with respect to that RBA Decision. For purposes of this Section, the term "Affected Parties" shall also include the Disputing Party.

Section 6.3.6 – Finality of ISO Action on Requested Billing Adjustment. Except as otherwise provided in this Section 6.3.6, the RBA Decision shall become final and binding on the Affected Parties and shall not be appealable in any forum on the twenty-first (21st) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above. The RBA Decision shall not become final or binding if, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, an Affected Party has appealed the RBA Decision by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, or has filed an appeal pursuant to Section 6.4 of the ISO New England Billing Policy. If a proceeding is commenced before the Commission or other regulatory or judicial authority with jurisdiction over the dispute, the Affected Party commencing that proceeding shall simultaneously transmit a copy of its initial pleading in that proceeding to the ISO's designated representative for that particular RBA Decision, and to the Chair of the NEPOOL Budget and Finance Subcommittee and shall also submit to the ISO's designated representative for that particular RBA a copy of the final order or decision in that proceeding resolving the dispute. If any such appeal is filed pursuant to Section 6.4 of the ISO New England Billing Policy, the RBA Decision shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process selected by the Affected Party and as provided for in the ISO New England Billing Policy.

Section 6.4 – Right of Affected Party to Review of ISO RBA Decision by AAA.

Section 6.4.1 – Right to Further Review. An Affected Party may seek review of an RBA Decision by an independent third party neutral by submitting, on or before the twentieth (20th) Business Day after the notice of the specific RBA Decision at issue was provided to the Affected Parties as set forth in Section 6.3.5 above, a request for arbitration of the Requested Billing Adjustment with the American Arbitration Association ("AAA"). At the same time that it submits its request to the AAA, the Affected Party commencing any such review of an RBA Decision shall transmit its request for arbitration: (i) to the ISO's designated representative for that particular RBA Decision; and (ii) to each of the Affected Parties; and (iii) to the Chair of the NEPOOL Budget and Finance Subcommittee. The ISO and any Affected Party shall be joined as parties to the arbitration. NEPOOL and other Covered Entities shall be permitted to intervene in the arbitration if they desire to do so.

Section 6.4.2 – Finality of the AAA Neutral's Decision. Except as otherwise provided in this Section 6.4.2, the written, final decision of the AAA neutral shall become final and binding on the Affected Parties, including the ISO, and shall not be appealable in any forum on the twenty-first (21st) Business Day after the date on which the final decision of the AAA neutral was issued. The final decision of the AAA neutral shall not become final or binding if on or before the twentieth (20th) Business Day after the date on which the final decision of the AAA neutral was issued, an Affected Party or Parties or the ISO has appealed the final decision of the AAA neutral by commencing a proceeding before the Commission or other regulatory or judicial authority with jurisdiction over the dispute. If any such appeal is filed, the final decision of the AAA neutral shall have no force or effect unless or until it is affirmed or upheld upon completion of the appeal process.

Section 6.5 – Access to Confidential Information. Information that is deemed confidential pursuant to the ISO New England Information Policy in the possession, custody or control of the ISO concerning the dollar amount in Invoices or Remittance Advices issued by the ISO ("Confidential Information") shall be made available under these billing dispute procedures only to "Dispute Representatives" who have executed a confidentiality agreement in accordance both with this Section 6.5 and the ISO New England Information Policy in the form of Attachment 1 hereto ("Confidentiality Agreement"). A copy of the executed Confidentiality Agreement for a Dispute Representative shall be provided to the ISO prior to the disclosure of any Confidential Information to said Dispute Representative. Confidential Information shall not be disclosed to anyone other than in accordance with this Section 6.5, and shall be used only in connection with the billing dispute procedures provided under this Section 6.

a) *Potential Disputing Parties' Right of Access to Confidential Information.* A Market Participant, PTO or Non-Market Participant Transmission Customer that is a potential Disputing Party is entitled to obtain access to Confidential Information for its Dispute Representative, if and only if, it can demonstrate to the ISO that such access is required to determine if it has a substantive basis for filing a Requested Billing Adjustment with the ISO. Such demonstration by a potential Disputing Party, at a minimum, shall include: the information submitted to ISO Participant Support and Solutions required in Section 6.3.1; and, why lack of access to Confidential Information prevents the potential Disputing Party from determining if it has a substantive basis for filing such a Requested Billing Adjustment. A potential Disputing Party shall submit a request for access to Confidential Information in writing to the ISO (an "Information Request"). The ISO shall evaluate and respond to such an Information Request within ten (10) days of the receipt of the Information Request, and where the need for access to Confidential Information is demonstrated in accordance with the above, shall provide access to such Confidential Information within fifteen (15) days of the receipt of the Information Request.

b) *Affected Parties Right of Access to Confidential Information*. If the RBA Decision is submitted to the AAA for resolution pursuant to Section 6.4, then for purposes of that AAA proceeding a Market Participant or Non-Market Participant Transmission Customer that is an Affected Party is entitled to obtain access to Confidential Information for its Dispute Representative if, and only if, it can demonstrate to the AAA Neutral that such access is required to protect its financial interests with respect to review of an RBA Decision pending before the Neutral. An Affected Party shall submit a request for access to Confidential Information concerning an RBA Decision within the timeframes established by the Neutral. The Neutral shall have the authority to enter such orders as may be necessary to protect the Confidential Information, in accordance with applicable ISO policies including but not limited to the ISO New England Information Policy.

c) *Dispute Representatives.* Dispute Representatives shall be limited to the AAA Neutral(s), Covered Entities and third parties retained by and/or in-house legal counsel of the AAA or Covered Entities; provided, however, that Confidential Information may not be disclosed to a Dispute Representative to the extent the disclosure is prohibited by Order 889. A Dispute Representative may disclose Confidential Information to any other Dispute Representative as long as the disclosing Dispute Representative and the receiving Dispute Representative each have executed a Confidentiality Agreement. In the event that any Dispute Representative to whom Confidential Information is disclosed ceases to be engaged in a matter under these billing dispute procedures, or is no longer qualified to be a Dispute Representative under this Section, access to Confidential Information by that person, or persons, shall be terminated and all such Confidential Information received by that party shall be returned to the ISO or destroyed to the satisfaction of the ISO. Even if no longer engaged as a Dispute Representative under this Section, every person who has executed a Confidentiality Agreement shall continue to be bound by the provisions of this Section and such Confidentiality Agreement. All Dispute Representatives are responsible for ensuring that persons under their supervision or control comply with this Section and the Confidentiality Agreement.

d) *Maintenance of Confidential Information.* All copies of all documents and materials containing Confidential Information shall be maintained by Dispute Representatives at all times in a secure place in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Section. Such documents and material shall be marked PROTECTED CONFIDENTIAL INFORMATION and shall be maintained under seal and provided only to Dispute Representatives as are authorized to examine and inspect such Confidential Informational. Dispute Representatives shall provide to the ISO a list of those persons under the supervision and/or control of the

Dispute Representative who are entitled to receive Confidential Information. Dispute Representatives shall take all reasonable precautions to ensure that Confidential Information is not distributed to unauthorized persons.

e) *ISO Right to Object to Access to Confidential Information*. Nothing in this Section shall be construed as precluding the ISO from objecting to providing any party access to Confidential Information on any legal grounds other than those provided under the ISO New England Information Policy, as it may be amended time to time.

SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES.

The ISO shall administer weekly billing arrangements for Non-Hourly Charges and Transmission Charges that have been effected in special circumstances pursuant to the ISO New England Financial Assurance Policy according to the following principles:

Section 7.1 - Weekly Invoices. The ISO shall issue weekly Invoices for such Non-Hourly Charges and such Transmission Charges to any Market Participant or Non-Market Participant Transmission Customer for which such a weekly billing arrangement has been established to the extent such Market Participant's or Non-Market Participant Transmission Customer's Non-Hourly Charges and Transmission Charges exceed the Payments due to it for Non-Hourly Charges and Transmission Charges, respectively, for the current billing week. Such weekly Invoices for Non-Hourly Charges and for Transmission Charges would be issued and due at the same times as one of the twice weekly Invoices for Hourly Charges as determined by the ISO. Remittance Advices for Non-Hourly Charges and for Transmission Charges for such Market Participants and Non-Market Participant Transmission Customers will still be issued monthly, in accordance with the procedures set forth above.

Section 7.2 -Basis for Billing. The amounts due from such Market Participant or Non-Market Participant Transmission Customer on weekly Invoices for Non-Hourly Charges and Transmission Charges shall be based on estimates derived by pro-rating the most recent final monthly Statements and Transmission Statements issued for such Market Participant or Non-Market Participant Transmission Customer.

Section 7.3 -Monthly Reconciliation. In connection with each monthly billing cycle, the ISO shall reconcile the sum of the weekly Invoices for Non-Hourly Charges and for Transmission Charges issued with the normal monthly billing quantities for such Non-Hourly Charges and Transmission Charges calculated for the Market Participant or Non-Market Participant Transmission Customer. The ISO shall perform a true-up of any amounts owed or due on the following weekly Statements or monthly Transmission Statements.

Section 7.4 – FTR-Only Customers. FTR-Only Customers are not eligible for weekly billing arrangements for Non-Hourly Charges.

Re: Requested Billing Adjustment ________________

CONFIDENTIALITY AND NONDISCLOSURE AGREEMENT

The ISO ("Provider") agrees to make available, pursuant to Section 6 of the ISO New England Billing Policy, to ________________________ ("Recipient") confidential and proprietary information (Confidential Information") relevant to resolution of the Requested Billing Adjustment ______ and any appeals thereof as provided for in said Section 6.

1. Any information provided to the Recipient and labeled "Confidential Information" by Provider shall be confidential subject to this Agreement.
2. The Confidential Information is received by Recipient in confidence.
3. The Confidential Information shall not be used or disclosed by the Recipient except in accordance with the terms contained herein, with Section 5 of the ISO New England Billing Policy and with the ISO New England Information Policy.
4. Only individuals who are Dispute Representatives as that term is defined in Section 6 of the ISO New England Billing Policy, and not entities, may be Recipients of Confidential Information under this paragraph. By executing this Agreement, each Recipient certified that he/she meets the requirements of this Agreement.
5. The following conditions apply to each Recipient:
    a. Each Recipient will receive one (1) numbered, controlled copy of the Confidential Information. The Recipient will not make any copies thereof or provide the Confidential Information to any individual or entity except one who has executed and delivered an Agreement identical to this Agreement to the Provider.
    b. The Recipient shall maintain a log of all persons granted access to the Confidential Information.
    c. The Recipient, by signing this Agreement acknowledges that he/she may not in any manner disclose the Confidential Information to any person, and that he/she may not use the Confidential Information for the benefit of any person except in this proceeding and in accordance with the terms of this Agreement, Section 6 of the ISO New England Billing Policy and the ISO New England Information Policy.
    d. The Recipient acknowledges that any violation of this Agreement may subject the Recipient to civil actions for violation thereof.
    e. Within thirty (30) days of the final decision issued with respect to the Requested Billing Adjustment terminating all appeals with respect to this Requested Billing Adjustment, Recipient shall return the Confidential Information to Provider.

PROVIDER:	RECIPIENT:
By: _________________________	By:__________________________
Dated:_______________________	Dated:________________________

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

> (i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.
>
> (ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this

calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) <u>**Real-Time Energy Market Deviations For Demand Response Resources**</u>

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **<u>Day-Ahead Energy Market Charge/Credit</u>** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **<u>Real-Time Energy Market Charge/Credit Excluding Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **<u>Real-Time Energy Market Charge/Credit For Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load

Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **<u>Non-Market Participant Loss</u>** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **<u>Inadvertent Energy Revenue</u>** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **<u>Inadvertent Energy Revenue Charges or Credits</u>** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy

quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; 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. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time

Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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. 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.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

  (a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

  (b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

    1. 35,437 MW; and
    2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

  (c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

    1. 35,090 MW; and
    2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

  (d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

    1. 34,865 MW; and
    2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic De-List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

  (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

  (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

  (i) that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $12.400/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.468/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e) (except that the bonus tax depreciation adjustment described in Section

III.A.21.1.2(e)(5) shall not apply). The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23, 2023/24 and 2024/25 Capacity Commitment Period, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23, 2023/24 and 2024/25 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions. A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2025.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

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 Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the 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) of the Capacity Acquiring Resource during the month 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) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Obligation Month.

(j) A resource that is not expected to achieve FCM Commercial Operation prior to the end of a given Obligation Month in accordance with posted schedules may not submit a transaction as a Capacity Acquiring Resource for that month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.
The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. 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 daily settlements 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 first Business Day of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Eligibility.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.13.5.3.2.1. Timing.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.13.5.3.2.2. Application.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.5.4 Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

III.13.5.4.1 Timing of Submission.

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

III.13.5.4.2 Components of an Annual Reconfiguration Transaction.

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;

(3) the resource identification number of the Capacity Acquiring Resource, and;

3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource's maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource's maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are settled on a daily basis during the applicable Capacity Commitment Period. The total of the daily payment amounts for the month is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.13.6.1.1.1. Energy Market Offer Requirements.

(a) 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:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a)(i) 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.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

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 potential referral under Section III.A.19.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.
A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(i) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(ii) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(iii) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

In all cases an Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.
A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(i) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(ii) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

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 (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.13.6.1.4. [Reserved.]

III.13.6.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.13.6.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.13.6.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

> (i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.

III.13.6.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Resource or Seasonal Peak Demand Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming FCM Commercial Operation as described in Section III.13.3.8, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new

Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Resources and Seasonal Peak Demand Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.13.6.1.5.4 and III.13.6.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.13.6.1.5.5 and the ISO New England Manuals.

III.13.6.1.5.4. On-Peak Demand Resource and Seasonal Peak Demand Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Resource and Seasonal Peak Demand Resource in every Capacity Commitment Period during which the On-Peak Demand Resource or Seasonal Peak Demand Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values will be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Resources consisting of Energy Efficiency measures, the ISO will calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Resources and Seasonal Peak Demand Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. (For Demand Capacity Resources, summer months are April through November; all other months are winter months.) Such an audit shall not satisfy the Passive DR Audit requirement.

III.13.6.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO will establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.

Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.13.6.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not 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. [Reserved.]

III.13.6.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the

Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.13.6.1.5.5 and the ISO New England Manuals; and

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource or a Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1.

III.13.7.1.1. Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period. Each monthly payment and charge listed in Section III.13.7.1.1 (a) through (d) below will be divided by the number of days in the month to derive a daily settlement value.

(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 and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six 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.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows.

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]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $9337/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section

III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.
For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.
The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of

the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation on any day of the Obligation Month shall be subject to the following charges and adjustments. Each charge and adjustment described in subsection (b) of Sections III.13.7.5.1.1.1 through III.13.7.5.1.1.9 will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

> Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.
>
> Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent

Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

> Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.
>
> Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.
>
> Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.
>
> Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

> Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.
>
> FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section

III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (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) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (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) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the total Capacity Load Obligation in all Capacity Zones less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.
The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Total Capacity Load Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation 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 Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation 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 for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each day of the month and each Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's daily Coincident Peak Contributions, to the sum of all load serving entities' daily Coincident Peak Contributions in that Capacity Zone.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each day of the month and each Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.
Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.
The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.
(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load

Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.
(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **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.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) 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 seasonal claimed capability of the ownership entitlements in such unit at the time of qualification, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. 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
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located, and; (ii) the MW quantity of the specifically allocated CTRs. This value will be divided by the number of days in the month to derive a daily settlement value.

III.13.7.5.5. 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 charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

SECTION III

MARKET RULE 1

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

APPENDIX I

FORM OF COST-OF-SERVICE AGREEMENT

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COST-OF-SERVICE AGREEMENT

This COST-OF-SERVICE AGREEMENT ("Agreement") is made as of the __ day of ______, 20__, among__________________________ ("Owner"), a _________{fill in type of legal entity}, __________________________ ("Lead Participant"), a _________{fill in type of legal entity}, acting as agent for Owner, and ISO NEW ENGLAND INC., a Delaware non-stock corporation ("ISO").

RECITALS

A. Owner is the owner of _____ ________ (Asset ID No. ___), a __________MW electrical generating station together with appurtenant facilities and structures,, located at ___________________(the "Resource"). {If the station is comprised of more than one unit, describe all units at the station, including their MW and Asset IDs, and then define the units that are subject to this Agreement as "Resources"}

B. [Owner is [the direct wholly-owned subsidiary of /affiliate of /unaffiliated with the] {specify relationship between Owner and Lead Participant} Lead Participant, [which is a Market Participant/both of which are Participants in the New England Markets.] Owner operates the Resource in accordance with the ISO New England Filed Documents and the ISO New England System Rules. Lead Participant administers the Resource in accordance with the ISO New England Filed Documents and the ISO New England System Rules and causes energy, capacity and ancillary services from the Resource to be offered for sale into the New England Markets on behalf of Owner.

C. ISO is the Regional Transmission Organization for New England and is responsible for the operation of the New England Control Area to ensure short-term reliability and the administration of the New England Markets.

D. [Owner / Lead Participant] submitted a [Permanent De-list Bid / Non-Price Retirement Request] for the Forward Capacity Auction for the Commitment Period starting June 1, ______.

E. ISO concluded that the Resource[s] will be needed for reliability purposes during the Term and expects the Resource may be required to run out-of-economic merit order to relieve transmission constraints; and as a result [rejected the Permanent De-list Bid / did not accept the Non-Price Retirement Request].

F. The Parties have agreed (i) that Owner shall cause an FPA Section 205 proceeding to be initiated to establish the Annual Fixed Revenue Requirement and (ii) to enter into this Agreement for supplying energy, ancillary services and capacity from the Resource[s] into the New England Markets and thereby (x) set the rate by which Owner shall receive its fixed costs for the Resource[s] from Participants and (y) govern how the Lead Participant shall cause bids to be made such that Owner receives from the Participants its variable costs for such supply.

NOW THEREFORE, in consideration of the agreements and covenants set forth herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound by this Agreement as of the Effective Date, the Parties covenant and agree as follows:

ARTICLE 1
DEFINITIONS AND RULES OF INTERPRETATION

1.1. Definitions.

Except for the terms defined below and in the attached schedules, capitalized terms shall be as defined in the Tariff, or other applicable market rules.

1.1.1. **"Additional Expenses"** shall mean costs associated with O&M Items in excess of the Fixed O&M Expenses.

1.1.2. **"Annual Fixed Revenue Requirement"** shall have the meaning set forth in Schedule 3.

1.1.3. **"Availability"** means the capability of the Resource, in whole or in part, at any given time, to produce energy, capacity, or ancillary services in accordance with Good Utility Practice, and "Available" shall be construed accordingly.

1.1.4. **"Effective Date"** shall have the meaning set forth in Section 2.1.

1.1.5. **"Fixed O&M Expenses"** shall have the meaning set forth in Schedule 3.

1.1.6. **"Force Majeure Event"** means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, any order, regulation or restriction imposed by a Governmental Authority, or any other cause beyond a Party's control.

1.1.7. **"Forced Outage"** means any outage of the Resource (other than a Planned Outage) that (i) is taken consistent with Good Utility Practice and applicable NERC criteria and (ii) fully or partially curtails the Resource's ability to supply energy, capacity and/or ancillary services.

1.1.8. **"FPA"** means the Federal Power Act.

1.1.9. **"Governmental Authority"** means the government of any nation, state or other political subdivision thereof, including any entity lawfully exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

1.1.10. **“Law”** means any law, treaty, code, rule, regulation, or order or determination of an arbitrator, court or other Governmental Authority, or any license, permit, certificate, authorization, qualification, or approval granted by a Governmental Authority to the extent binding on a Party or any of its property.

1.1.11. **“Month”** means the period beginning at 12:00 a.m. on the first day of the calendar month and ending at 12:00 a.m. of the first day of the next succeeding calendar month.

1.1.12. **“Monthly Reports”** shall have the meaning set forth in Section 4.4.4.

1.1.13. **“Monthly Settlement”** means the monthly settlement process set forth in the ISO New England Manuals.

1.1.14. **“Notice of Additional Expenses”** shall have the meaning set forth in Section 7.1.2(e).

1.1.15. **“Notice of Forced Outage”** shall have the meaning set forth in Section 7.1.2(b).

1.1.16**. “Notice of Shut-down”** shall have the meaning set forth in Section 7.1.2(c).

1.1.17. **“O&M Expenses”** see “Fixed O&M Expenses”

1.1.18. **“O&M Items”** means fixed O&M costs of repairs of the Resource and replacements of any part of the Resource to correct or avoid any impairment of the capability of the Resource to supply energy, capacity and/or ancillary services, which Owner expenses during the same calendar year in which it is performed, in accordance with Owner’s accounting practices.

1.1.19. **“Owner”** shall have the meaning set forth in the preamble of this Agreement and, where applicable and appropriate, its assignee and/or designee.

1.1.20. **“Party”** means either the ISO or Owner or Lead Participant as the context requires, and “Parties,” means ISO and Owner and/or Lead Participant, as the context requires.

1.1.21. **“Periodic Cost Report”** shall have the meaning set forth in Section 6.1.1.

1.1.22. **“Planned Outage,”** means a planned interruption, in whole or in part, in the electrical output of a Resource to permit Owner to perform maintenance and repair of the Resource, including O&M Items.

1.1.23. **“Resource”** shall have the meaning set forth in the Recitals.

1.1.24. **“Resource Characteristics”** shall have the meaning set forth in Section 3.4

1.1.25. **“Shut-down”** shall have the meaning set forth in Section 7.1.2(c).

1.1.26. **“Shut-down Date”** shall have the meaning set forth in Section 7.1.2(f).

1.1.27. **“Stipulated Marginal Cost”** shall have the meaning set forth in Section 3.4.

1.1.28. **“Stipulated Variable Cost”** shall have the meaning set forth in Section 3.4.

1.1.29. **“Stipulated Start-Up Cost”** shall have the meaning set forth in Section 3.4.

1.1.30. **“Stipulated No-Load Cost”** shall have the meaning set forth in Section 3.4.

1.1.31. **“Stipulated Regulation Offer”** shall have the meaning set forth in Section 3.4

1.1.32. **“Supplemental Capacity Payment”** shall have the meaning set forth in Schedule 3.

1.1.33. **“Term”** shall have the meaning set forth in Section 2.1.

1.1.34. **“Variable O&M”** shall be the amount specified in Schedule 1.

1.2. Interpretation.

In this Agreement, unless otherwise indicated or otherwise required by the context, the following rules of interpretation shall apply:

1.2.1. Reference to and the definition of any document (including this Agreement, ISO New England Filed Documents and the ISO New England System Rules) shall be deemed a reference to such document as it may be amended, supplemented, revised, or modified from time to time and any document that is a successor thereto.

1.2.2. The article and section headings, and other captions in this Agreement are for the purpose of reference only and do not limit or affect its meaning.

1.2.3. Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine or neuter gender shall include all genders.

1.2.4. Accounting terms used herein shall have the meanings given to them under generally accepted accounting principles within the United States consistently applied.

1.2.5. The term “including” when used herein shall be by the way of example only and shall not be considered in any way a limitation.

1.3. Construction.

This Agreement has been drafted by the Parties hereto and shall not be construed against any Party as the sole drafter.

ARTICLE 2
TERM

2.1. Effective Date and Term.

If ISO has not notified the Owner that the Resource is no longer needed for reliability reasons by 12:00 am on June 1 of the year preceding the Capacity Commitment Period for which [the Permanent De-List Bid was rejected / the Non-price Retirement Request was not accepted], this Agreement shall be effective at the beginning of the operating hour ending at 1:00 a.m., June 1, 200___ (the "Effective Date") and shall terminate at the end of the operating hour beginning at 11:00 p.m. as of the date of the termination of the [last] Resource as provided in Section 2.2 ("Term").

2.2. Termination.

This Agreement may be terminated as follows:

2.2.1. Once this Agreement is effective, it shall remain in effect for at least a 12-month Capacity Commitment Period. ISO shall terminate this Agreement as to [the/a] Resource effective any time after such minimum 12-month term upon one hundred twenty (120) days written notice to Owner when ISO determines that [the/a] Resource is no longer needed for system reliability. The one-hundred twenty day notice may be issued by ISO prior to the completion of the minimum 12-month term. If two or more Resources are subject to this Agreement, the Agreement may be terminated with respect to one or more individual Resources. The Agreement terminates as of the date that ISO has terminated the Agreement with respect to all of the Resources that were subject to the Agreement as of the Effective date. Owner shall provide timely notice of any such termination of this Agreement to the Commission.

2.2.2. Upon 30 days notice to the Owner, the ISO may unilaterally terminate this Agreement if, over the twelve (12) month period preceding the notice, the ISO determines that the average value over all hours in that period of the ratio of the Resource's Economic Maximum as it may be redeclared from time to time to the Capacity Supply Obligation is less than fifty percent (50%). Owner shall retain all of its existing rights to challenge the ISO's calculation under the ISO Billing Policy.

2.2.3. This Agreement may be terminated as provided in Section 7.1.2, Section 9.2 and Section 11.4.

2.2.4. Consequence of Termination or Expiration. [One of the following alternatives shall be applicable to each Resource]

[Inasmuch as the Owner submitted a Permanent De-List Bid, upon termination, the provisions of Market Rule 1, Section III.13.2.5.2.5 apply and as of the date of termination the Resource is de-listed, relieved of its Capacity Supply Obligation, and no longer receives compensation under the Agreement. In addition, the Resource is no longer eligible to participate as an Existing Resource in any reconfiguration auction, Forward Capacity Auction, or Capacity Supply Obligation Bilateral for the then current Capacity Commitment Period or subsequent periods of Capacity Commitment Periods.]

[Inasmuch as the Owner submitted a Non-Price Retirement Request, unless pursuant to Market Rule 1 Section III.13.1.2.3.1.5 the Commission has directed that the obligation to retire be removed, upon termination the provisions of Market Rule 1 Section III.13.2.5.2.5 shall apply, and, as of the date of termination, the Resource is de-listed, relieved of its Capacity Supply Obligation, and no longer receives compensation under this Agreement. In addition, upon termination of the Agreement, the interconnection rights for the Resource shall terminate and the status of the Resource will be converted to retired.]

2.3. Survival.

Notwithstanding the termination of this Agreement, the Parties shall continue to be bound by the provisions of this Agreement which by their nature are intended to, and shall, survive such termination.

ARTICLE 3
RIGHTS AND OBLIGATIONS

3.1. In General.

During the Term, the Resource is a listed Generating Capacity Resource with a Capacity Supply Obligation. The Owner and Lead Participant shall operate, maintain and administer the Resource in accordance with (a) this Agreement, (b) the ISO New England Filed Documents, (c) the ISO New England System Rules, and (d) Good Utility Practice, as applicable. Nothing herein shall be construed as to require the Owner or Lead Participant to take action that is contrary to Good Utility Practice.

3.2. Insurance.

Owner shall arrange for and maintain an appropriate level of liability and property insurance with respect to the Resource consistent with Good Utility Practice.

3.3. Bilateral Agreements.

The Resource will not be subject to any bilateral agreement for the sale or control of energy, capacity, or ancillary services from the Resource, unless the Owner or Lead Participant, as applicable, provides the ISO with a written copy of the proposed agreement at least 30 days in advance. If, upon the Effective Date, the Owner is not the registered Owner in ISO's Customer and Asset Management System (CAMS) for the full output of the Resource, the Owner shall provide the ISO with a written copy of any agreement between the Owner and the Registered Owner within seven days.

3.4. Supply Offers.

For each day, the Lead Participant shall offer for sale energy and ancillary services into the New England Markets from the Resource based on the characteristics and operating parameters specified in Schedule 2 (the "Resource Characteristics") and with Supply Offers equal to the Stipulated Variable Costs as provided below. Lead Participant shall use commercially reasonable efforts to cause the submittal of Supply Offers for hourly values of Economic Minimum and Economic Maximum that are consistent with ambient air forecasts and /or environmental permit parameters. [Lead Participant also shall offer Regulation into the New England Markets from the Resource based on the Resource Characteristics using only Stipulated Regulation Offers as defined below.]

3.4.1. The Stipulated Variable Costs shall be self-adjusting formulary rates accepted by the Commission pursuant to the FPA Section 205 proceeding initiated by Owner and updated daily or at the most frequent time interval permitted under the ISO New England System Rules. Stipulated Variable Costs shall be determined according to the definitions below using parameter values from Schedule 1.

Stipulated Marginal Cost ("SMC") per MWh	=	(Fuel + O&M + Other)

Where:

Fuel	=	Heat Rate, MMBTU/MWh x (Fuel Index Price, $MMBTU, +Approved Fuel Variable Transportation Service Charges, $MMBTU) + Fuel Cost Other per MWh]
O&M	=	Variable O&M for energy production per MWh as specified in Schedule 1
Other	=	(SO2 Allowance Adder + NOx Allowance Adder + CO2 Allowance Adder + Other Allowance Adder + Operating Permit Adder)

Stipulated Variable Costs	=	Stipulated Marginal Cost + Stipulated Start-Up Cost + Stipulated No-Load Cost

Where:

Stipulated Start-Up Cost per Start	=	(Start-Up Fuel Use x Fuel Index Price, $/MMBTU) + Start-Up O&M + Start-Up Other (as specified in Schedule 1)
Stipulated No-Load Cost per Service	=	(No Load Fuel Use, MMBTU x Fuel Index Price, $/MMBTU) + Fuel Cost Ancillaries + Hour No Load O&M + No-Load Other (as specified in Schedule 1)

3.4.1.1 The "Fuel Index Price" shall mean the current daily price, using the third party data as specified on Schedule 1, applicable to the delivery point specified on Schedule 1.

3.4.1.2 ["Stipulated Regulation Offer" shall mean the actual offer for providing Regulation from the Resource, which shall not exceed $[100] or the cap specified in Market Rule 1, as may be amended from time to time. {Note: Owner/Lead Participant to discuss with Market Monitoring if Resource has supplied regulation service}].

3.5. Self-Scheduling.

As long as a fuel limitation does not result, and subject to the ISO New England System Rules, the ISO New England Operating Documents and the compensation provisions of Article 4, the Lead Participant may request to self-schedule the Resource for operational and maintenance considerations, including testing, and fuel management purposes . ISO System Operations may accept or not accept the self-schedule in its sole discretion

ARTICLE 4
COMPENSATION AND SETTLEMENT

4.1. In General.

The Owner is subject to charges and credits for services in the New England Markets, including the Supplemental Capacity Payment, in accordance with the ISO New England System Rules and the ISO New England Administrative Procedures, with settlement taking place in the normal weekly and monthly settlement processes as they may be amended from time to time. If an entity other than the Owner has been registered as the Owner in the ISO's Customer and Asset Registration System ("Registered Owner"), then the Supplemental Capacity Payment shall be settled through the account of the Registered Owner unless the Owner has a settlement account with the ISO and, after consent by ISO, the Owner, Registered Owner and Lead Participant provide written authorization to settle the Supplemental Capacity Payment through the Owner's Settlement Account. The Owner, Registered Owner and Lead Participant must comply with all ISO requirements for customer and asset registration.

4.2. Variable Cost Recovery.

In order to provide for recovery of variable costs, the Supply Offers applicable to the Resource as determined in accordance with Section 3.4. shall be included in the calculation of Net Commitment Period Compensation ("NCPC") and the Revenue Credit as defined below. All NCPC shall be paid in accordance with applicable ISO settlement procedures.

4.3. Fixed-Cost Recovery.

Owner shall be entitled to a Supplemental Capacity Payment for the Resource for each Month, calculated in accordance with Schedule 3, which ISO shall cause to be paid by Participants through the monthly settlement process for the New England Markets. The Annual Fixed Revenue Requirement shall be as determined by the Commission pursuant to an FPA Section 205 proceeding initiated by Owner.

4.4. Revenue Credit.

4.4.1. In General. All revenues related to the Resource less the variable costs of producing those revenues ("Revenue Credit") shall reduce the Supplemental Capacity Payment in accordance with the formulas in Schedule 3.

4.4.2. FCA Payments. The Revenue Credit shall include the FCA Payment as it has been adjusted for Peak Energy Rent and Availability Penalties in the normal FCA settlement. The adjusted amount is allowed to be negative in the calculation of the Revenue Credit and to increase the Supplemental Capacity Payment (when that part of the calculation is viewed in isolation). Provided, however, any Availability Credits earned pursuant to the provisions of Market Rule 1, Section III.13.7.2.7.1.4 shall be ignored for calculating the Revenue Credit and shall inure to the benefit of the Owner, subject to the maximum earnings provision of Schedule 3, Part 1.

4.4.3. Revenues Received in the New England Markets. All revenues related to the Resource earned in the New England Markets settled by ISO (in addition to the revenues earned in the Forward Capacity Market above), less the Stipulated Variable Cost of producing those revenues as represented by the Supply Offers, shall be included in the calculation of the Revenue Credit. For self-scheduled hours, inframarginal revenue shall not be reduced for Stipulated Variable Costs in excess of hourly revenue. Monthly inframarginal revenue is the sum of all daily positive inframarginal revenue values. If the revenues related to the Resource are not paid on a Resource specific basis, the ISO shall allocate such revenues to the Resources that are subject to this Agreement.

4.4.4. Other Revenues. Any revenues related to the Resource that have not been settled by ISO (including from bilateral agreements, emission credits, release of firm transportation arrangements, sale of surplus equipment etc.), less any incremental costs directly related to securing additional revenue that are not already accounted for in the Annual Fixed Revenue Requirement or Stipulated Variable Costs, will be included in the Revenue Credit. These incremental costs may not be greater than the incremental revenues on a case-by-case basis. The Owner and Lead Participant shall report all such other revenues, or the absence thereof, to ISO in a monthly report (the “Monthly Report”).

ARTICLE 5
MARKET MONITORING

5.1. Mitigation.

Although this Agreement provides for Supply Offers that do not exceed thresholds identified in Appendix A, Market Rule 1, nothing herein shall preclude the ISO from otherwise applying any provision of Appendix A to Market Rule 1 to Owner or Lead Participant, any Affiliate of Owner or Lead Participant, the Resource, or any other resources of Owner or Lead Participant or any Affiliate of Owner or Lead Participant, including mitigation of Supply Offers for Resources covered by this Agreement to the applicable Stipulated Variable Cost as defined in Section 3.4.

5.2. Adjustment.

After consultation with the Lead Participant, Supply Offers that exceed Stipulated Variable Cost are subject to adjustment by ISO Market Monitoring to Stipulated Variable Cost.

5.3. Dual Fuel Resources [If dual fuel].

The Lead Participant is required to submit Supply Offers reflecting the fuel to be used. If the Lead Participant is to submit Supply Offers based on the higher cost fuel, it must advise ISO Market Monitory as soon as practicable in advance of submitting such an offer and provide a written explanation as to the cause, Availability implications and expected duration.

ARTICLE 6
REPORTING

6.1. Variable Cost and Resource Characteristic Reporting.

6.1.1. Owner shall update the components of Stipulated Variable Costs that are not publicly available as they may change from time to time on a timely basis, along with supporting information as requested, in a format approved by ISO and consistent with the formulas provided in Section 3.4 and Schedule 1 (the "Periodic Cost Report"). If Owner fails to provide updated information on a timely basis, Supply Offers may be adjusted to Stipulated Variable Costs based on the information on file. ISO will give Owner 30 days prior written notice of any change in the form of the Periodic Cost Report.

6.1.2. The Resource Characteristics applicable to the Resource during the Term are set forth in Schedule 2 hereto. Owner shall provide ISO with updated Resource Characteristics set forth on a revised Schedule 2 immediately upon any change of those Resource Characteristics. If ISO does not agree to the revised Schedule, the Schedule in effect shall remain in effect during the Term pending alternative dispute resolution in accordance with Appendix D to Market Rule 1.

6.2. Books and Records; Audit Rights.

ISO shall have the right, at any time upon reasonable notice, to examine at reasonable times the books and records of Owner and Lead Participant to the extent necessary to audit and verify the accuracy of all reports, statements, invoices, charges, or computations pursuant to this Agreement. The Parties acknowledge and agree that ISO may perform audits of the Monthly Reports and the Periodic Cost Reports as well as a final audit of all expenses incurred under this Agreement upon completion of the Term. All information provided during the course of such an examination shall be treated as confidential information under applicable ISO Protocols.

ARTICLE 7
RESOURCE OPERATION AND MAINTENANCE

7.1. Planned and Forced Outages.

7.1.1. Planned Outages. Owner shall be entitled to take the Resource out of operation or reduce the net capability of the Resource during Planned Outages, in accordance with the schedule for Planned Outages as established and implemented pursuant to the ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA.

7.1.2. Forced Outages.

(a) Generally. Owner shall be entitled to take the Resource out of operation or reduce the net capability of the Resource upon the occurrence of a Forced Outage.

(b) Notice of Forced Outage. In the event of a Forced Outage that is anticipated to last for more than ten (10) days, in addition to any other notification obligation arising under ISO New England System Rules, the Transmission, Markets and Services Tariff and the MPSA, Owner shall promptly notify ISO Reliability Contract Services in writing of its occurrence, estimated duration, and whether Additional Expenses are expected to be required to return the Resource to service (a "Notice of Forced Outage"). Owner shall also inform ISO of the availability of any previously retired unit (the “Substitute Unit”) and the costs and time required to bring the Substitute Unit back into service and to retire the Resource on Forced Outage.

(c) Notice of Shut-down. As soon as reasonably practicable after the date of a Notice of Forced Outage but in no event greater than thirty (30) days from the start of such Forced Outage, either Party may, after assessing the nature, expected duration, and expected incurrence of Additional Expenses, notify the other in writing of its determination that the Resource shall, subject to the provisions of Section 7.1.2(e), be Shut-down (a "Notice of Shut-down") and if such notice applies to the entire Resource that this Agreement should be terminated.

(d) Supplemental Capacity Payment. In the event that the Resource is Shutdown, Owner shall only remain entitled to receive the Supplemental Capacity Payment based on the AFRR through the Shut-down Date; provided that with respect to a Shut-down applying only to a unit, this Agreement shall remain in full force and effect with respect to the remaining unit(s). Owner may file amendments to the AFRR with the Commission.

(e) Option to Approve Additional Expenses. With respect to a Notice of Shutdown made by Owner, if within thirty (30) days of receipt of Owner's Notice of Shut-down ISO provides written notice to Owner that it is willing to pass through for payment by the Participants in the Monthly Settlement process of the New England Markets such Additional Expenses (a "Notice of Additional Expenses") that may be required to recover from such Forced Outage, Owner agrees that it will, with reasonable dispatch, take the action requested by ISO, i.e., not Shut-down the Resource and make such Additional Expenses as paid to it by the Participants to return the Resource to service from such Forced Outage, or make such expenditures as paid to it by the Participants to bring the Substitute Unit into service and retire the Resource on Forced Outage. The Parties agree that the effectiveness of a Notice of Additional Expenses shall be immediately effective, and Owner shall be entitled to begin receiving payments from ISO pursuant thereto, as of the day following the date the Owner files a request under Section 205 of the FPA with the Commission to recover from ISO the Additional Expenses identified in the Notice of Additional Expenses. Payments will be made subject to refund pending the approval of such Additional Expenses by the Commission. The Parties further agree that Owner is obligated to use its best efforts to minimize Additional Expenses and that the amounts approved under the Notice of Additional Expenses are subject to offset by any proceeds from any and all third-party sources, including insurance proceeds, paid to Owner to return the Resource from the Forced Outage. Owner shall make a subsequent reconciliation ("true-up") filing with the Commission and refund any payments for Additional Expenses paid to Owner that are disallowed by the Commission, or that exceed the amount actually expended by the Owner, after offsets.

(f) Shut-down Date. With respect to a Notice of Shut-down issued by ISO pursuant to Section 7.1.2(c), the "Shut-down Date" shall be that date ten (10) days after the receipt of such Notice of Shut-down by the Owner. With respect to a Notice of Shut-down issued by Owner pursuant to Section 7.1.2(c), the "Shut-down Date" shall be that date thirty (30) days after the receipt of such Notice of Shutdown by ISO unless ISO has issued a Notice of Additional Expenses in accordance with Section 7.1.2(e), in which case no Shut-down Date will have occurred with respect to such Notice of Shut-down or the Shut-down Date will be the date on which the Substitute Unit is brought back into service. As of the Shutdown Date, the interconnection rights for the Resource shall terminate and the status of the Resource will be converted to retired.

7.2. Additional and Other Expenses.

Except as provided for in Section 7.1, Owner shall (i) not be required or otherwise obligated to incur any Additional Expenses and (ii) not be required to enter into any additional agreements or incur any additional costs, including fixed-fuel costs, that Owner is not already obligated to enter into, or incur, as the case may be, that are not otherwise contemplated by, and being recovered by Owner pursuant to, the Annual Fixed Revenue Requirement.

ARTICLE 8
FORCE MAJEURE EVENTS

8.1. Notice of Force Majeure Event.

If any Party is unable to perform its obligations under this Agreement due to a Force Majeure Event, the Party unable to perform shall promptly notify the other Party.

8.2. Effect of Force Majeure Event.

If the Availability of the Resource is reduced by reason of a Force Majeure Event, Section 7.1.2 shall apply (i.e. a Force Majeure Event shall be deemed to create a Forced Outage). Subject to reduction by the COS Availability Penalty and to Sections 7.1.2, 9.2, and 11.4, Owner shall continue to receive the Supplemental Capacity Payment without any other reduction while the Force Majeure Event continues.

8.3. Remedial Efforts.

The Party unable to perform by reason of a Force Majeure Event shall use reasonable efforts to remedy its inability to perform and to mitigate the consequences of the Force Majeure Event as soon as reasonably practicable; provided that (i) no Party shall be required to settle any strike, walkout, lockout, or other labor dispute on terms which, in the Party's sole discretion, are contrary to its interests and (ii) subject to Sections 7.1.2 and 7.2, the Party unable to perform shall, as soon as practicable, advise the other Party of the reason for its inability to perform, the nature of any corrective action needed to resolve performance, and its efforts to remedy its inability to perform and to mitigate the consequences of its inability to perform and shall advise the other Party of when it estimates it will be able to resume performance of its obligations under this Agreement.

ARTICLE 9
REMEDIES

9.1. Damages and Other Relief.

9.1.1. Liability of ISO. ISO shall not be liable to Owner or Lead Participant for actions or omissions by ISO in performing its obligations under this Agreement, provided it has not willfully breached this Agreement or engaged in willful misconduct. To the extent Owner or Lead Participant has claims against ISO, Owner and Lead Participant may only look to the assets of ISO for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees or agents of ISO who, Owner and Lead Participant acknowledge and agree, have no personal liability for obligations of ISO by reason of their status as directors, members, officers, employees or agents of ISO.

9.1.2. Liability of Owner. Except as provided by the COS Availability Penalty, Owner and Lead Participant shall not be liable to ISO for actions or omissions by Owner or Lead Participant in performing their obligations under this Agreement, provided that Owner or Lead Participant has not willfully breached this Agreement or engaged in willful misconduct.

9.1.3. Limitation of Liability. In no event shall Owner and Lead Participant be liable to ISO or ISO be liable to Owner and Lead Participant for any incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance of this Agreement.

9.1.4. Indemnification. Owner and Lead Participant shall indemnify, defend and save harmless ISO and its directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by ISO under this Agreement or the actions or omissions of Owner and Lead Participant in connection with this Agreement, except in cases of gross negligence or willful misconduct by ISO or its directors, officers, members, employees or agents.

9.2. Termination for Default.

If any Party shall fail to perform any material obligation imposed on it by this Agreement and that obligation has not been suspended pursuant to this Agreement, the other Party, at its option, may terminate this Agreement by giving the Party in default written notice setting out specifically the circumstances constituting the default and declaring its intention to terminate this Agreement. If the Party receiving the notice does not within ten (10) days after receiving the notice, remedy the default, the Party not in default shall be entitled by a further written notice to terminate this Agreement. The Party not in default shall have a duty to mitigate damages. Termination of this Agreement pursuant to this Section 9.2 shall be without prejudice to the right of any Party to collect any amounts due to it prior to the time of termination.

9.3. Waiver.

The failure to exercise any remedy or to enforce any right provided in this Agreement or applicable Law shall not constitute a waiver of such remedy or right or of any other remedy or right. A Party shall be considered to have waived any remedies or rights only if the waiver is in writing.

9.4. Beneficiaries.

Except as is specifically set forth in this Agreement, nothing in this Agreement, whether express or implied, confers any rights or remedies under, or by reason of, this Agreement on any persons other than the Parties and their respective successors and assigns, nor is anything in this Agreement intended to relieve or discharge the obligations or liability of any third party, nor give any third person any rights of subrogation or action against any Party.

ARTICLE 10
COVENANTS OF THE PARTIES

10.1. ISO represents and warrants to Owner and Lead Participant as follows:

10.1.1. ISO is a validly existing corporation with full authority to enter into this Agreement.

10.1.2. ISO has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of ISO.

10.1.3. ISO has all regulatory authorizations necessary for it to perform its obligations under this Agreement.

10.1.4. The execution, delivery, and performance of this Agreement are within ISO's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.2. Owner represents and warrants to ISO as follows:

10.2.1. Owner is a validly existing entity with full authority to enter into this Agreement.

10.2.2. Owner has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Owner.

10.2.3. Owner has, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.2.4. The execution, delivery, and performance of this Agreement are within the Owner's powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

10.3. Lead Participant represents and warrants to ISO as follows:

10.3.1. Lead Participant is a validly existing entity with full authority to enter into this Agreement.

10.3.2. Lead Participant has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery of this Agreement, this Agreement shall be a legally binding obligation of Agent.

10.3.3. Lead Participant has, or has applied for, all regulatory authorizations, necessary for it to perform its obligations under this Agreement.

10.3.4. The execution, delivery, and performance of this Agreement are within the Lead Participants powers and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party, or any Law applicable to it.

ARTICLE 11
MISCELLANEOUS PROVISIONS

11.1. Assignment.

11.1.1. None of the Parties shall assign its rights or delegate its duties under this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Upon any assignment made in compliance with this Article 11.1, this Agreement shall inure to and be binding upon the successors and assigns for the assigning Parties.

11.1.2. Notwithstanding Section 11.1.1, each Party may, without the need for consent from the other Party (and without relieving itself from liability hereunder), transfer or assign this Agreement: (i) to an Affiliate, or (ii) where such transfer is incident to a merger or consolidation with, or transfer of all, or substantially all, of the assets of the transferor to another person, business entity, or political subdivision or public corporation created under the Laws governing the creation and existence of the transferor which shall as a part of such succession assume all of the obligations of the assignor or transferor under this Agreement. Provided, however, that any Party who transfers or assigns this Agreement as provided in subsections “i” or “ii” of this Section 11.1.2 shall provide timely notice to the other Party or Parties of such change, including the effective date and changes, if any, to the nominations under Section 11.2 and Exhibits A or B, as appropriate. Any Party may collaterally assign its rights in this Agreement to its lenders without the need for consent from the other Party. To the extent that any Party seeks to transfer its rights and obligations to a successor entity, such Party shall seek to assign this Agreement to such successor entity, pursuant to this Section 11.1.2.

11.1.3. Upon 60 days notice from Owner or Lead Participant, the Lead Market Participant’s role under this Agreement may terminate and then this function must be assigned by Owner to another entity fully capable of fulfilling this role consistent with the ISO New England Filed Documents and the ISO New England System Rules. The Owner, the current Lead Participant, and the successor Lead Participant must comply with all ISO requirements for Customer Asset registration. Owner is not obligated to assign the Lead Market Participant role to another entity and may assume this role, if it is qualified to do so, by notifying the ISO.

11.1.4. The Owner may designate a new Registered Owner by providing 30 days notice under the Agreement and a written copy of any agreement between the Owner and the new registered Owner. The Owner, the Registered Owner and the Lead Participant must comply with all ISO requirements for Customer and Asset registration.

11.2. Notices.

Except as otherwise expressly provided in this Agreement or required by Law, all notices, consents, requests, demands, approvals, authorizations and other communications provided for in this Agreement shall be in writing and shall be sent by personal delivery, certified mail, return receipt requested, facsimile transmission, or by recognized overnight courier service, to the intended Party at such Party's address set forth below. All such notices shall be deemed to have been duly given and to have become effective: (a) upon receipt if delivered in person or by facsimile; (b) two days after having been delivered to an air courier for overnight delivery; or (c) seven days after having been deposited in the United States mail as certified or registered mail, return receipt requested, all fees pre-paid, addressed to the applicable addresses set forth below. Each Party's address for notices shall be as follows (subject to change by notice in accordance with the provisions of this Section 11.2):

OWNER AND LEAD PARTICIPANT:
NOTICES & CORRESPONDENCE
[TO COME]

ISO:
NOTICES & CORRESPONDENCE
[Name], [Title]
ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040
Tel: [to be provided] Fax: [to be provided]

with a copy to:
[Name], [Title]

ISO New England Inc.
One Sullivan Road Holyoke, MA 01040
Tel: [to be provided] Fax: [to be provided]

The foregoing notice provisions may be modified by providing written notice, in accordance with ISO Protocols established from time-to-time.

11.3. Parties' Representatives.

All Parties to this Agreement shall ensure that throughout the term of this Agreement, duly appointed representatives are available for communications between the Parties. The representatives shall have full authority to deal with all day-to-day matters arising under this Agreement. Acts and omissions of representatives shall be deemed to be acts and omissions of the Party. Owner and ISO shall be entitled to assume that the representatives of the other Party are at all times acting within the limits of the authority given by the representatives' Party. Owner's and Lead Participants representatives shall be identified on Exhibit A. ISO's representatives shall be identified on Exhibit B. The Parties may at any time replace their representatives by sending the other Party a revision to its respective Exhibit.

11.4. Effect of Invalidation, Modification, or Condition.

Each covenant, condition, restriction, and other term of this Agreement is intended to be, and shall be construed as, independent and severable from each other covenant, condition, restriction, and other term. If any covenant, condition, restriction, or other term of this Agreement is held to be invalid or otherwise modified or conditioned by any Governmental Authority, the invalidity, modification, or condition of such covenant, condition, restriction, or other term shall not affect the validity of the remaining covenants, conditions, restrictions, or other terms hereof. If an invalidity, modification, or condition has a material impact on the rights and obligations of the Parties, the Parties shall make a good faith effort to renegotiate and restore the benefits and burdens of this Agreement as they existed prior to the determination of the invalidity, modification, or condition. If the Parties fail to reach agreement, then the Party whose rights and obligations have been adversely affected may, in its sole discretion, terminate this Agreement or refer the dispute for resolution under the Alternative Dispute Resolution provisions in Appendix D of Market Rule 1.

11.5. Amendments.

Any amendments or modifications of this Agreement shall be made only in writing and duly executed by all Parties to this Agreement. Such amendments or modifications shall become effective only after the Parties have received any authorizations required from the Commission. The Parties agree to negotiate in good faith any amendments to this Agreement that are needed to reflect the intent of the Parties as expressed herein and to reflect any changes to the design of the New England Markets that are approved by the Commission from time to time.

11.6. Governing Law.

This Agreement shall be governed by and construed under the Laws of the Commonwealth of Massachusetts without regard to conflicts of laws principles.

11.7. Entire Agreement.

This Agreement consists of the terms and conditions set forth herein, as well as the Appendices hereto, which are incorporated by reference herein and made a part hereof. This Agreement contains the entire agreement between the Parties and supersedes all prior negotiations, undertakings, agreements and business term sheets.

11.8. Independent Contractors.

Owner (and Lead Participant, as Owner's representative) and ISO acknowledge that as between Owner and ISO there is an independent contractor relationship, and that nothing in this Agreement shall create any joint venture, partnership, or principal/agent relationship between the Parties. Neither Owner or Lead Participant nor ISO shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

11.9. Counterparts.

This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same agreement.

11.10. Confidentiality.

Confidential information identified as such by a Party and provided to the other Party pursuant to this Agreement shall be governed by the ISO New England Information Policy, subject to the following:

11.10.1. Nothing herein or therein shall limit the right of a Party to file a copy of this Agreement with the Commission, without redaction, to the extent that law, regulation, or agency order makes such filing necessary or appropriate.

11.10.2. Notwithstanding anything in this Agreement to the contrary, if during the course of an investigation or otherwise, the Commission requests that a Party (the "responding Party") provide to it information that has been designated by the other Party to be treated as confidential under this Agreement, the responding Party shall provide the requested information to the Commission or its staff within the time provided for in the request for information. The responding Party shall promptly notify the other Party upon receipt of any such request and either Party, consistent with 18 CFR § 388.112, may, but shall not be required, to request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure.

11.11. Submittal to the Commission.

The Parties acknowledge and agree that (i) the Annual Fixed Revenue Requirement and the formula for calculating Stipulated Variable Costs shall be established pursuant to an FPA Section 205 proceeding to be initiated by application of Owner provided, however, that any application for changes to the formula for calculating Stipulated Variable Costs shall be made only under Section 206; (ii) this Agreement constitutes the basis for Owner's recovery of its fixed and variable costs for operating and maintaining the Resource during the Term.

IN WITNESS WHEREOF, this Agreement has been executed as of the date first above written.

[OWNER NAME]
By:
Name:
Title:

ISO NEW ENGLAND INC.
By: Name:
Title:

[LEAD PARTICIPANT NAME]
By: Name:
Title:

EXHIBIT A

OWNER'S AND LEAD PARTICIPANT'S REPRESENTATIVES

[OWNER AND LEAD PARTICIPANT TO PROVIDE]

EXHIBIT B

ISO'S REPRESENTATIVES

[Name]

[Title]

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

SCHEDULE 1

INFORMATION ON MARGINAL COST

[The Lead Participant or Owner shall provide the ISO, on a timely basis in advance of the Section 205 filing prior to the commencement of the Capacity Commitment Period, with draft Schedule 1 and Schedule 2 including supporting cost and other information, as the ISO may require.]

1. The Fuel Index Price for the Resource:

a. Natural Gas – specify price index, delivery point, pipeline and Local Distribution Company ("LDC").

b. Applicable gas contract including any transportation charges, Other Fossil fuel – specify price index, delivery type (barge, tanker, rail, truck). Applicable fuel contract, including any transportation agreements and applicable (sales) tax.

Each Fuel Index Price shall use the following data source(s), respectively, as appropriate:

[Check applicable box]

☐Energy/Petroleum Argus
☐Intercontinental Commodities Exchange ("ICE")
☐Other (as mutually agreed)________________

[Check applicable box]

Fuel Type	**Frequency of Data**
☐Coal_	weekly
☐Natural Gas	daily (business days)
☐No2	daily (business days)
☐No2_LS_aka_DIESEL	daily (business days)
☐No6_030	daily (business days)
☐No6_070	daily (business days)
☐No6_100	daily (business days)

☐No6_220 daily (business days)

☐No6_300 daily (business days)

☐Jet_fuel daily (business days)

☐LS_Jet_kero daily (business days)

2. Based on the following delivery point__________________________. The Heat Rate for use with the Fuel Index Price for the Resource to calculate Marginal Fuel Cost is set forth in the following table[s for each fuel type] expressed in MMBTU/MWh]. The table shows the incremental heat rate (include a minimum of four data points, ranging from zero output and including Ecomin and Ecomax values). Dual fuel units should provide this data on a fuel specific basis.

3. Provide information about any other components of the marginal fuel cost, including variable transportation and Fuel Cost Ancillaries, if any.

4. Provide information on Variable O&M for energy production, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3. (Dual fuel units should provide this data on a fuel specific basis).

5. Provide information about any other components of marginal costs, including emission allowance adders and operating permit adders, if any. (Express NOx, SO2, CO2 and any other emission rates in Lbs/MMBTU. (Dual fuel units should provide this data on a fuel specific basis).

6. Provide information about Start-Up Costs. Stipulated Start-up costs are variable costs that are incurred prior to synchronization and when operating below EcoMin, to the extent those variable costs are not recovered in the energy market or NCPC, as shown in the following table(s) for each fuel type:

a. (on a fuel specific basis): fuel input (mmBtu's);

b. O&M component for starts, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3, itemized; and,

c. "Start-Up other", itemized, if applicable

7. Provide information about No-Load Costs. No-load costs are those costs that vary in the service hours and are independent of output and are as shown in the following table(s) for each fuel type:

a. (on a fuel specific basis): input (mmBtu's);

b. No-Load O&M component for Service Hours, consistent with the study supporting the Annual Fixed Revenue Requirement as shown in Schedule 3, itemized; and

c. No-Load Other, itemized, if applicable.

For example [add columns for other parameters, including CO2 emission rate as necessary]:

SAMPLE TABLE

Fuel Type

____

Data Source Daily Price Survey midpoint

Delivery Point ________________

Net Output (may have up to 10 segments)	Marginal Heat Rate (mmBTU/MWh)	Fuel Ancillaries ($/kWh)	Variable O&M ($/MWh)	NOx Emission Rate (lbs/MWh)*	SO2 Emission Rate (lbs/MWh)**
0 MW to EcoMin of e.g., 30 MW	10.200	N/A	$1.84	2.55	0.31
31 MW - 60 MW	10.750	N/A	$1.84	2.69	0.32
61 MW - 90 MW	11.600	N/A	$1.84	2.90	0.35
90 MW – Eco Max e.g., 107 MW	12.300	N/A	$1.84	3.08	0.37

Start-Up	Fuel (mmBTU)	Start-Up Fuel Ancillaries ($/mmBTU)	Start-Up O&M ($/start)	NOx Emission Rate (lbs/start)*	SO2 Emission Rate (lbs/start)**
Cold	400	N/A	$0	100	12
Intermediate	350	N/A	$0	88	11
Hot	300	N/A	$0	75	9

No Load Conditions	No Load Fuel (mmBTU/hr)	Start-Up Fuel Ancillaries ($/mmBTU)	No Load NOx Emission Rate (lb/hr)*	No Load SO2 Emission Rate (lb/hr)*
	81	N/A	20.25	2.43

- As referenced in Section 3.4, "Supply Offers," the NOx Allowance Adder shall be calculated as: the appropriate NOx Emission Rate from the table above times the daily quoted price of average trades in $/ton as posted by Evolution Markets, LLC on http://www.evomarkets.com, divided by 2000 (lbs/ton).

- As referenced in Section 3.4, “Supply Offers,” the SO2 Allowance Adder shall be calculated as: the appropriate SO2 Emission Rate from the table above times the daily quoted price of average trades in $/ton as posted by Evolution Markets, LLC on http://www.evomarkets.com, divided by 2000 (lbs/ton).

- For use in calculating the Resource's Stipulated Bid Costs, the NOx emission rate shall only be included for bids submitted for operation during the NOx season (May through September of each calendar year).

* NOx Emission Rate = [e.g., 0.25] lb/mmbtu on natural gas

** SO2 Emission Rate = [e.g., 0.03] lb/mmbtu on natural gas

SCHEDULE 2
RESOURCE CHARACTERISTICS

[RESOURCE NAME]
(NOTE: for combine cycles, provide the following for each mode of operation)

EcoMin:	__________	
Qualified Capacity*	__________ MW (Winter)	__________MW (Summer)
EcoMax (emergency) (as applicable gas/oil:		__________MW
Ramp Rate (Normal):		__________MW/Minute
Ramp Rate (emergency):		__________MW/Minute
Minimum Run Time:		__________hours
Minimum Shutdown Time:		__________hours
Notification Time (Cold):**		__________hours
Start-Up Time (Cold Conditions)***:		__________hours
Notification Time (Warm)**		__________hours
Start-Up Time (Warm Conditions)***:		__________hours
Notification Time (Hot)**		__________hours
Start-Up Time (Hot Conditions)		__________hours
Start-Up Profile		__________(MWh)_________(MMBTU)
Shut-Down Profile		__________(MWh)_________(MMBTU)

*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 process (Market Rule III.1.3.2) including challenge provisions as appropriate.

** “Notification Time” is defined consistent with eMarket specifications as the time required from an ISO-issued start order to the synchronization of the Resource.

*** “Start Up Time” is defined consistent with eMarket specifications as the time required from synchronization of the Resource to the time the Resource reaches its EcoMin level of output and available for ISO dispatch.

For each day, Lead Participant shall use commercially reasonable efforts to cause the submittal of Supply Offers for hourly values of EcoMax and EcoMin that are consistent with ambient atmospheric conditions and equipment operating conditions.

SCHEDULE 3
SUPPLEMENTAL CAPACITY PAYMENT

For each Obligation Month during the Term, a Supplemental Capacity Payment shall be calculated for the Resource[s] as set forth below. The Supplemental Capacity Payment shall be charged to Regional Network Load in the affected Reliability Region.

Section III.13 references are to Market Rule 1, Section III.13 – Forward Capacity Market.

The Annual Fixed Revenue Requirement (AFRR) for the [generating station / Resource] is $___________.

The Annual Fixed O&M Expenses for the [generating station / Resource] is $___________.

The AFRR is the cost-of-service for the [generating station / Resource], including fixed operation and maintenance expenses, depreciation, amortization, taxes and return, as accepted by the Commission. The Annual Fixed O&M Expenses is the fixed operating & maintenance expense component of the AFRR. Where the AFRR and the Annual Fixed O&M Requirement have been determined for a generating station that is composed of two or more Resources, each shall be allocated to the Resources pro-rata according to their Capacity Supply Obligations as of the Effective Date. [list the allocated amounts below.]

(Part 1)

Supplemental Capacity Payment =

Plus: Maximum Monthly Fixed Cost Payment

Less: Total COS Availability Penalties for the Obligation Month

Less: Revenue Credit for the Obligation Month

Providing that for any given Capacity Commitment Period the monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the AFRR (subject to the additional provisions of Part 5 if applicable).

In the event that the Supplemental Capacity Payment would otherwise be less than zero in any Obligation Month, the Supplemental Capacity Payment for that Obligation Month shall be zero and any unapplied COS Availability Penalty or Revenue Credit shall roll-forward for crediting in a future Obligation Month.

For the last Obligation Month of the Term, the ISO shall charge the Owner for any unapplied roll-forward amount and shall refund that amount to Regional Network Load (subject to the additional provisions of Part 5 below if applicable).

(Part 2)

Maximum Monthly Fixed Cost Payment = AFFR / 12

COS Price = Maximum Monthly Fixed Cost Payment / Capacity Supply Obligation

The Total COS Availability Penalty for the Obligation Month equals the sum of the COS Availability Penalties for each Shortage Event that has been defined and recognized in accordance with Sections III.13.7.1.1.1 through III.13.7.1.1.4. The COS Availability Penalty for each Shortage Event shall be determined in accordance with the provisions of Section III.13.7.2.7.1.2, except that it shall be based on the COS Price instead of the Capacity Clearing Price and the Annual Fixed Revenue Requirement instead of the Resource's Annualized FCA Payment. The per day and per month COS availability penalties assessed shall be subject to the caps set forth in Section III.13.7.2.7.1.3, except that the caps shall be based on the Annual Fixed Revenue Requirement rather than the Resource's Annualized FCA Payment. The sum of Total COS Availability Penalties for each Capacity Commitment Period shall not exceed the Annual Fixed Revenue Requirement.

(Part 4)

The purpose of the Revenue Credit is to recognize that the Resource has earned revenues from sources other than this Supplemental Capacity Payment. The Supplemental Capacity Payment is reduced accordingly so that the Resource receives a total payment for its capacity during the Commitment Period equal to its Annual Fixed Revenue Requirement reduced for any COS Availability Penalties.

Revenue Credit for the Obligation Month =

Plus: FCA Payment for the Obligation Month

Less: Availability Penalty for the Obligation Month

Plus: All other revenues related to the Resource (i.e. all revenues except for revenues from the New England Forward Capacity Market) that are in excess of Stipulated Offer Costs. Provided, however, any Availability Credits earned according to the provisions of

Section III.13.7.2.7.1.4 shall be ignored for calculating this Revenue Credit and shall inure to the benefit of the Owner subject to the provisions of Part 1.

Where the FCA Payment and Availability Penalty for the Obligation Month are the amounts calculated in the normal monthly settlement based on the Capacity Clearing Price for the Capacity Zone and the provisions of Section III.13.7.

(Part 5)

If this Agreement terminates other than at the end of a Capacity Commitment Period:

5.1 The ISO shall credit the Resource for Availability Penalties and COS Availability Penalties during that Capacity Commitment Period that are in excess of the pro-rated Annualized FCA Payment and AFRR respectively. The ISO shall charge the appropriate Market Participants defined in Section III.13.7.3 and Regional Network Load in the Reliability Region according to which entities had received the benefit of these excess Availability Penalties and COS Availability Penalties.

5.2 The monthly Supplemental Capacity Payments are capped so that the cumulative value of Supplemental Capacity Payments plus Revenue Credits plus Availability Credits (as defined in Section III.13.7.2.7.1.4) shall not exceed the prorated AFRR.

(Part 6)

While the roll-forward provisions of Part 1 provide that the Supplemental Capacity Payment cannot result in a monthly charge to the Resource because of a Supplemental Capacity Payment that calculates to a negative amount, nothing in this Agreement provides that the sum of all charges and credits for the Resource cannot result in a net amount owed to the ISO for any Obligation/Operating Month.

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