



February 2, 2022

VIA ELECTRONIC FILING

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

Re: Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets; Docket No. ER22-____-000

Dear Secretary Bose:

Pursuant to Rule 1907 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“the Commission”),¹ ISO New England Inc. (“ISO” or “ISO-NE”),² joined by the New England Power Pool (“NEPOOL”) Participants Committee and the PTO Administrative Committee (“PTO AC”) on behalf of the New England Participating Transmission Owners (“PTOs”) (together, the “Filing Parties”),³ hereby electronically submits this transmittal letter and revisions to Sections I, II and III of the Tariff to comply with the Commission’s Order

¹ 18 C.F.R. § 385.1907 (2021).

² Capitalized terms used but not otherwise defined in this filing have the meanings ascribed to them in ISO-NE’s Transmission, Markets and Services Tariff (the “Tariff”) or the Second Restated NEPOOL Agreement, the Participants Agreement, and the Transmission Operating Agreement (“TOA”).

³ Under New England’s Regional Transmission Organization (“RTO”) arrangements, the rights to make this filing of changes to Schedule 23 of the ISO-NE OATT, and certain defined terms in Section I.2.2 of the Tariff under Section 205 of the FPA are shared by ISO-NE and the PTOs in the manner specified in the Transmission Operating Agreement between ISO-NE and the PTOs (the “TOA”). The rights to make this filing of changes to Market Rule 1 and the remainder of the defined terms in Section I.2.2 of the Tariff are ISO-NE’s. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO-NE matters, supported the changes reflected in this filing and, accordingly, joins in this Section 205 of filing.

Nos. 2222, 2222-A, and 2222-B.⁴ The proposed Tariff revisions are collectively referred to as the “Compliance Proposal.”

Issued on September 17, 2020, pursuant to Section 206 of the Federal Power Act,⁵ Order No. 2222 adopts reforms to remove barriers to the participation of Distributed Energy Resource Aggregations (“DERAs”) in markets operated by Regional Transmission Organizations and Independent System Operators (“RTOs/ISOs”). In Order No. 2222, the Commission found that existing RTO/ISO market rules were unjust and unreasonable “in light of barriers that they present to the participation of DERAs in RTO/ISO markets, which reduce competition and fail to ensure just and reasonable rates.”⁶ Therefore, the Commission modified its regulations to require that RTOs/ISOs revise their tariffs to facilitate the participation of DERAs in wholesale markets by establishing Distributed Energy Resource Aggregators (“DER Aggregators”) as a type of market participant that can register DERAs under one or more participation models in the RTO/ISO tariff that accommodate the physical and operational characteristics of each DERA.

Through this filing, the Filing Parties submit modifications to the Tariff in compliance with the requirements of Order No. 2222. As more fully explained below, the proposed Tariff modifications create a pathway for DERAs to participate in New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources (“DERs”); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities (“RERRAs”) for DERA/DER registration, operations, and dispute resolution purposes.

The Filing Parties respectfully request that the Commission accept the Compliance Proposal as filed herein, without modifications or conditions. For the reasons discussed below, the Filing Parties submit that the Tariff rules contained in the Compliance Proposal meet the requirements of Order No. 2222 by establishing the pathway for any DERA to offer into New England Markets all the wholesale services that they are technically capable of providing.

I. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

ISO-NE is the private, non-profit entity that serves as the RTO for New England. ISO-NE plans and operates the New England bulk power system and administers New England’s organized wholesale electricity markets pursuant to the Tariff and the TOA with the PTOs. In its capacity as an RTO, ISO-NE has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by Northeast

⁴ *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020) (“Order No. 2222”); Order Addressing Arguments Raised on Rehearing, Setting Aside Prior Order in Part, and Clarifying Prior Order in Part on Rehearing 174 FERC ¶ 61,197 (2021) (“Order No. 2222-A”); Order Addressing Arguments Raised on Rehearing, Setting Aside in part and Clarifying in Part Prior Order, 175 FERC ¶ 61,227 (2021) (“Order No. 2222-B”).

⁵ 16 U.S.C. § 824e (2020).

⁶ Order No. 2222 at P 1.

Power Coordinating Council, Inc. and the North American Electric Reliability Corporation (“NERC”).

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement that has grown to include more than 510 members. The members, which are also referred to as “Participants,” include all of the electric utilities rendering or receiving service under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, developers, demand resource providers, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,⁷ the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Processes for advisory voting on [ISO-NE] matters and the selection of [ISO-NE] Board members, except for input from state regulatory authorities and as otherwise may be provided in the [ISO-NE] Tariff, TOA and the Market Participant Services Agreement included in the [ISO-NE] Tariff.”

Pursuant to the terms of the TOA among the PTOs⁸ and ISO-NE, the PTOs own, physically operate and maintain Transmission Facilities in New England and ISO-NE has Operating Authority (as defined in Schedule 3.02 of the TOA) over all of the Transmission Facilities of the PTOs, including those used to provide Local Service over non-Pool Transmission Facilities under Schedule 21 of the ISO-NE OATT. Section 3.04 of the TOA also grants the PTOs authority under Section 205 of the FPA to submit filings to the Commission in matters affecting the rates, terms and conditions of Local Service under Schedule 21 and rates and charges, including cost allocation, for Regional Transmission Service under the ISO-NE OATT.

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

⁸ The PTOs include: Town of Braintree Electric Light Department; Central Maine Power Company; Maine Electric Power Company; Chicopee Electric Light Department; Connecticut Municipal Electric Energy Cooperative; Connecticut Transmission Municipal Electric Energy Cooperative; Versant Power (f/k/a Emera Maine) (Bangor Hydro District); The City of Holyoke Gas and Electric Department; Green Mountain Power Corporation; Town of Hudson Light and Power Department; Massachusetts Municipal Wholesale Electric Company; Town of Middleborough Gas & Electric Department; New England Power Company d/b/a National Grid; New Hampshire Electric Cooperative, Inc.; New Hampshire Transmission, LLC; Eversource Energy Service Company on behalf of certain of its affiliates: The Connecticut Light and Power Company, NSTAR Electric Company, and Public Service Company of New Hampshire; Taunton Municipal Lighting Plant; Town of Norwood Municipal Light Department; Town of Reading Municipal Light Department; The United Illuminating Company; Unitil Energy Systems, Inc.; Fitchburg Gas and Electric Light Company; Vermont Electric Power Company; Vermont Electric Cooperative, Inc.; Vermont Transco, LLC; Vermont Public Power Supply Authority; Shrewsbury Electric and Cable Operations; Town of Wallingford, Connecticut Department of Public Utilities Electric Division; and Stowe Electric Department.

Correspondence and communications in this proceeding should be addressed to:

ISO NEW ENGLAND INC.

Graham Jesmer, Esq.*
Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
Tel: (413) 535-4045
E-mail: gjesmer@iso-ne.com

Michael J. Thompson, Esq.*
Abraham F. Johns III, Esq.
Wright & Talisman, P.C.
1200 G Street, N.W.,
Suite 600
Washington, D.C. 20005
Tel: (202) 393-1200
Email: thompson@wrightlaw.com
johns@wrightlaw.com

**NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE**

William Fowler
Vice-Chair
NEPOOL Markets Committee
c/o Sigma Consultants, Inc.
20 Main Street
Acton, MA 01720
Tel: (978) 266-0220
Email: wfowler@sigmaconsult.com

Eric K. Runge, Esq.*
Rosendo Garza, Jr., Esq.
Counsel for NEPOOL
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
Tel: (860) 275-0663
Email: ekrunge@daypitney.com
rgarza@daypitney.com

PTO AC

Alan Trotta
Chair, PTO Administrative Committee
c/o Avangrid Service Company
180 Marsh Hill Road
Orange, CT 06477
Tel.: (203) 499-3271
E-mail: Alan.Trotta@uinet.com

Mary E. Grover, Esq.*
Chair, PTO AC Legal Working Group
c/o Eversource Energy
800 Boylston Street, P1700
Boston, MA 02199-8003
Tel: (617) 424-2105
E-mail: mary.grover@eversource.com

*Persons designated for service.⁹

⁹ 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.

II. BACKGROUND AND PROCEDURAL HISTORY

A. Order No. 2222

In Order No. 2222, the Commission found that “existing RTO/ISO market rules are unjust and unreasonable because they present barriers to the participation of distributed energy resource aggregations in the RTO/ISO markets, and such barriers reduce competition and fail to ensure just and reasonable rates.”¹⁰ Specifically, the Commission stated that “current RTO/ISO market rules present barriers that prevent certain distributed energy resources that are technically capable of participating in the RTO/ISO markets on their own or through aggregation from doing so.”¹¹ Therefore, the Commission required that ISOs/RTOs reduce barriers to the participation of DERs in wholesale markets by allowing DERAs to participate in wholesale markets through the establishment of new, or the modification of existing, market participation models.

Order No. 2222 enumerated eleven directives for RTOs/ISOs: (1) establish distributed energy resource aggregators as a type of market participant; (2) allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models; (3) establish a minimum size requirement not to exceed 100 kW; (4) address locational requirements; (5) address distribution factors and bidding parameters; (6) address information and data requirements; (7) address metering and telemetry requirements; (8) address coordination between the RTO/ISO, the distributed energy resource aggregator, the distribution utility, and the RERRAs; (9) address modifications to the list of resources in a distributed energy resource aggregation; (10) address market participation agreements; and (11) create an opt-in for small utilities (i.e., utilities that distributed 4 million megawatt hours (“MWh”) or less in the previous fiscal year).¹²

The Commission allowed RTOs/ISOs flexibility in meeting the requirements of Order No. 2222, noting that RTOs/ISOs were free to propose new tariff provisions as well as identify existing tariff provisions that met the requirements of the Order.¹³ The Compliance Proposal addresses each of these compliance directives, and the methods used to comply with each directive are discussed in turn in Section III of this filing letter below.

Order No. 2222 required RTOs/ISOs to submit compliance filings within 270 days of the order’s publication in the Federal Register,¹⁴ and to “propose a reasonable implementation date, together with adequate support explaining how the proposal is appropriately tailored for its region

¹⁰ Order No. 2222 at P 26.

¹¹ *Id.*

¹² *Id.* at P 8.

¹³ Order No. 2222 states that RTOs/ISO will have “flexibility to determine how best to revise the participation models set forth in its market rules to facilitate the participation of distributed energy resource aggregations.” *Id.* at P 130. It also states that this approach “will allow each RTO/ISO to reflect varying regional needs in its approach to allow distributed energy resource aggregators to participate in its markets.” *Id.* at P 132.

¹⁴ *Id.* at P 360.

and implements this final rule in a timely manner.”¹⁵ The Order was published in the Federal Register on October 22, 2020 and, therefore, compliance filings were originally due on July 19, 2021. As explained below, however, the Commission granted the ISO an extension to file its Compliance Proposal on or before February 2, 2022.

B. Order No. 2222-A

On March 18, 2021, the Commission issued Order No. 2222-A, which addressed arguments raised on rehearing, and also set aside in part, and clarified in part, the Commission’s determinations in Order No. 2222. The Commission set aside the finding that the participation of demand response resources in DERAs is subject to the opt-out and opt-in requirements of Order Nos. 719 and 719-A. Instead, Order No. 2222-A ruled that if a DERA includes only resources that participate as demand response resources, then the Order No. 719 opt-out would apply to that aggregation. However, if a DERA contains any resources that participate as another type of DER, then the Order No. 719 opt-out would not apply to that aggregation.¹⁶

The Commission also provided clarification regarding restrictions to avoid double counting of services, information sharing in the distribution utility review process, and distribution utility review criterion.¹⁷ With respect specifically to matters related to double counting, the Commission clarified, that RTOs/ISOs were not required to put in place restrictions on DERA participation by a DER that is participating in a retail program if the RTO/ISO has mechanisms in place to prohibit the same DER acting as a provider of that service in the same delivery period. Order No. 2222-A states in relevant part that:

“[W]hen the Commission stated that ‘if a distributed energy resource is offered into an RTO/ISO market and is not added back to a utility’s or other load serving entity’s load profile, then that resource will be double counted as both load reduction and a supply resource,’ the Commission was indicating that, for planning purposes, double counting of services would occur if the same distributed energy resource reduces the amount of a service that an RTO/ISO procures on a forward-looking basis in a certain time period while also acting as a provider of that same service in that same delivery period.”¹⁸

C. Order No. 2222-B

In response to Order No. 2222-A, certain parties sought further clarification of Paragraph 63 of Order No. 2222-A—or, in the alternative, rehearing—that behind-the-meter DERs used to serve onsite load, should be compensated at full Locational Marginal Price (“LMP”) in compliance with Order No. 745, with no need to eliminate retail savings generated by the distributed energy resource, and that payment of full LMP to behind-the-meter DERs does not constitute double

¹⁵ *Id.* at P 361.

¹⁶ *See* Order No. 2222-A at PP 22-30.

¹⁷ *Id.* at PP 63, 75, 79.

¹⁸ Order No. 2222-A at P 63 (footnote omitted).

counting or double compensation for services whether procured on a forward-looking basis or in real-time.

Relying on *FERC v. Electric Power Supply Association*,¹⁹ these parties argued that the Commission has authority to authorize RTOs/ISOs to pay demand response resources full LMP;²⁰ and that the principles of Order No. 745 should apply to all reductions in load achieved by DERAs from the perspective of the bulk power system, regardless of the method or methods used to achieve that reduction; and that Order No. 2222 proposals that pay such DERs less than full LMP would not enhance competition or ensure just and reasonable rates.²¹

On June 17, 2021, the Commission issued Order No. 2222-B, clarifying that DERs participating in a DERA, that are not Demand Response Resources (“DRRs”) as defined under Order Nos. 745 and 719, need not be compensated at full LMP, but that the Commission would consider compliance proposals that did so. Specifically, the Commission stated that:

“If the distributed energy resource participates as demand response, the requirements in Order No. 745 would apply, and the RTOs/ISOs are required to allow that distributed energy resource to aggregate with other types of distributed energy resources in a heterogeneous distributed energy resource aggregation. If the behind-the-meter resource participates as another type of distributed energy resource (i.e., not as a demand response resource), the requirements in Order No. 745 would not apply.”²²

D. ISO-NE Extension Request

On April 16, 2021, ISO-NE filed a request for an extension of time to make its Order No. 2222 compliance filing. The ISO requested an extension until February 2, 2022, in order to provide ISO-NE, RERRAs, electric distribution companies, Transmission Owners, Host Participant Assigned Meter Readers, prospective DER Aggregators, and other New England stakeholders sufficient time to develop a compliance proposal that met the requirements in Order No. 2222, as clarified in Order Nos. 2222-A and 2222-B, respectively.

The Commission granted the ISO’s request on May 24, 2021, and required that the ISO submit periodic stakeholder process updates to the Commission. The ISO filed update reports in June, September, and December 2021, providing the Commission with the status of the stakeholder process as of each point in time. These updates indicated that the ISO continued on the same schedule provided with its extension request, and was on track to submit the compliance filing on February 2, 2022.

¹⁹ *FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260 (2016) (“*EPSA*”).

²⁰ AEE/AEMA Motion for Clarification (April 19, 2021) at pp. 3-4.

²¹ *Id.* at p. 5.

²² Order No. 2222-B at P 44 (footnote omitted).

III. DESCRIPTION OF THE COMPLIANCE PROPOSAL

The Compliance Proposal is designed to integrate DERAs with the ISO-NE markets and operational constructs as set out in the ISO's Governing Documents and Operating Documents, as well as the roles and responsibilities of the ISO and the PTOs as set forth in the TOA. The ISO administers the Forward Capacity Market, and energy and ancillary services markets. The Forward Capacity Market procures wholesale capacity market service on a three-year forward basis to better ensure that adequate resources are available in real-time to meet expected energy and reserve requirements. The energy and ancillary services markets include several different markets: Day-Ahead Energy Market, Real-Time Energy Market (which includes the procurement of both Energy and Operating Reserves in real-time), Regulation Market, and Forward Reserve Market—these markets procure energy injection service, energy withdrawal service, demand reduction service, reserve services (both real-time Operating Reserves and forward reserves), and regulation products.²³

ISO-NE, working with regional stakeholder through the NEPOOL process, has revised existing participation models, and designed new participation models that fit into this existing market structure. This approach will allow DERAs to provide all of the services currently sold in the New England Markets to the extent they are technically capable of doing so. In order to accommodate DERAs, the Compliance Proposal includes minor conforming changes to existing participation models to the extent necessary, but the Compliance Proposal does not alter the existing services, or introduce new services offered in the New England Markets. This is consistent with Order No. 2222, which did not require the ISO to create new wholesale services, nor modify the fundamental qualities of the services currently procured through the New England Markets. Rather, Order No. 2222 requires that ISOs/RTOs allow DERs, through DERAs, to participate in all of its existing wholesale markets and to provide all of the services they are technically capable of providing.

The following sections discuss the Compliance Proposal and are organized based on the Commission's enumerated compliance directives. Each section discusses the proposed Tariff language included in the Compliance Proposal, how the proposed language complies with Order No. 2222, and why the proposed design is reasonable in light of the structure of the New England Markets and the ISO's Governing and Operating Documents.

1. Order No. 2222 Directive: Allow Participation of Distributed Energy Resource Aggregations

Order No. 2222 requires that RTOs/ISOs allow DERAs to participate directly in RTO/ISO markets and that they establish DER Aggregators as a type of market participant. To further this requirement, the Commission required that RTOs/ISOs adopt definitions for DER and DER Aggregator in order to enable their participation in wholesale markets through DERAs.²⁴ The

²³ In New England, the Day-Ahead Energy Market only procures energy at this time; but the Real-Time Energy Market procures both energy and real-time reserves on a co-optimized basis using the Real-Time Energy Market offers submitted by resources.

²⁴ Order No. 2222 at PP 114-18.

Commission stated that “RTOs/ISOs can propose their own definitions for the Commission’s evaluation as long as the scope and applicability of the proposed definitions are consistent with the Commission’s definition of distributed energy resource and consistent with all aspects of this final rule.”²⁵

Consistent with the Commission’s directive and the allowed flexibility, the Compliance Proposal adopts the Commission’s definitions in Section I.2.2 of the Tariff with limited modifications specific to ISO-NE’s proposed market participation models and Governing Documents.

First, the Compliance Proposal sets forth the following definition of DER as follows:

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter *that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.* (deviations emphasized).

The proposed additions to the DER definition are necessary to ensure that DERs seeking to aggregate have the capabilities necessary to use the participation models proposed in the Compliance Proposal. These distinct capabilities—i.e., energy injection, energy withdrawal, regulation, and demand reduction—are discussed in further detail in the participation models section below.

Next, the Compliance Proposal modifies the definition of DER Aggregator as follows:

Distributed Energy Resource Aggregator (DER Aggregator) is a *Market Participant* that aggregates one or more Distributed Energy Resources for participation in a *Distributed Energy Resource Aggregation* and serves as the *Lead Market Participant for a Distributed Energy Resource Aggregation.* (deviations emphasized)

The additional language emphasized in the definition of DER Aggregator leverages current ISO-NE Tariff terminology to describe the role of a DER Aggregator in relation to the ISO and the New England Markets. For example, the current Tariff uses the term “Lead Market Participant” to refer to “the entity authorized to submit Supply Offers, Demand Bids” on behalf of a Resource, or to “the entity designated to participate in [the Forward Capacity Market] on behalf of an Existing Capacity Resource or a New Capacity Resource.”²⁶

Since DER Aggregators will be submitting Supply Offers, Demand Bids, Demand Reduction Offers, or Baseline Deviation Offers, or participating in the Forward Capacity Market, on behalf of a DERA, the DER Aggregator would be fulfilling the role of a Lead Market Participant as per the ISO’s current Tariff construct. The Commission has accepted similar terminology

²⁵ *Id.* at P 115.

²⁶ *See* Tariff Section I.2.2. Definitions.

variations in the past and this is consistent with the flexibility offered in Order No. 2222.²⁷

In addition to these definitions, the Compliance Proposal also includes revised or new definitions for a number of terms connected with the participation models. These revisions, which are reflected in Section I.2.2 of the Tariff, are discussed in the sections of this transmittal letter for the relevant participation models. The modifications include, but are not limited to, new definitions for Distributed Energy Resource Aggregation and Distributed Energy Capacity Resource, as well as modified definitions for Asset, Resource, and Lead Market Participant. Having clearly defined terms in Section I.2.2 helps ensure that the Tariff obligations for DER Aggregators are clear, consistent, and transparent.

2. Order No. 2222 Directive: Participation Models

Order No. 2222 requires that RTOs/ISOs allow DER Aggregators to register DERAs under one or more participation models that accommodate the physical and operational characteristics of the DERA. The Commission required that RTOs/ISOs modify existing participation models, create new participation models, or employ some combination thereof in order to allow for the participation of DERAs. The Commission, however, provided RTOs/ISOs with “flexibility to determine how best to revise the participation models set forth in its market rules to facilitate the participation of distributed energy resource aggregations.”²⁸ Compliance proposals are required to accommodate the physical and operational characteristics of each DERA to enable them to provide all the services that each is technically capable of providing. Participation models must also be technology neutral and allow for heterogeneous mixes of technologies, including Order No. 745 compliant DRRs, in a DERA, and for the participation of single resource aggregations.²⁹ Reasonable restrictions, however, are allowed to prevent the double counting of services in wholesale markets.³⁰ RTOs/ISOs must also specify in their Tariffs the eligibility criteria for participation as a DERA.³¹

The Tariff revisions contained in the Compliance Proposal allow DERs with a mix of technologies to participate in a DERA. The Commission’s direction in Order No. 2222 is clear. The rules for DERA participation in wholesale markets must be technology neutral and based on the technical *capabilities* of the aggregated resource rather than on the technologies comprising the resource.³² Accordingly, the ISO developed DERA participation models based on specified technical capabilities. These capabilities include:

- Energy injection – Refers to the capability to inject an amount of energy into the electric system as measured from the resource’s Point of Interconnection (“POI”)

²⁷ See, e.g. ISO New England Inc., 170 FERC ¶ 61,209, at P 44 (2020) (accepting variation from Commission adopted definitions to reflect differences in ISO-NE terminology and interconnection queue approach).

²⁸ Order No. 2222 at P 120.

²⁹ *Id.* at P 141.

³⁰ *Id.* at P 161.

³¹ *Id.* at P 130.

³² *Id.* at PP 114, 141.

or Retail Delivery Point (“RDP”).³³ A resource with energy injection capability would be paid for energy supplied to the electric system at the LMP. Resources with the proper characteristics can also supply Operating Reserves and wholesale capacity market services.

- Energy withdrawal – Refers to the capability to withdraw an amount of energy from the electric system as measured from the resource’s POI or RDP. A resource with energy withdrawal capability would be billed for the energy it withdraws from the electric system at the LMP, and would be billed for capacity based on its consumption during system peak. Dispatchable loads with the proper characteristics can avoid capacity charges and can also supply Operating Reserves.
- Demand reduction – Refers to the capability to reduce demand from the electric system as measured against a baseline established at the resource’s RDP. A resource with demand reduction capability can sell demand reductions into the Energy Market at the LMP. Resources with the proper characteristics can also supply Operating Reserves and wholesale capacity market services.
- Regulation – Refers to the capability to balance supply and demand on the electric system by changing energy injection or energy withdrawal every four seconds. A resource with regulation capability can supply regulation products in the ISO-NE Regulation Market, which would be compensated at Regulation Market clearing prices.

The proposed participation models recognize that each DERA, comprised of one or more DERs, could have one or more capabilities, which in turn could lead to the provision of one or more types of wholesale services. The participation models described below allow DERAs to be properly compensated for each service they provide to the market.

i. Proposed Energy and Ancillary Services Market Participation Models

For purposes of participation in the ISO-NE energy and ancillary services markets, the Compliance Proposal allows DER Aggregators to use the existing participation models, some with minor modifications to comply with Order No. 2222. These existing participation models are:

- Generator Asset,
- Continuous Storage Facility (“CSF”),
- Binary Storage Facility (“BSF”),
- Alternative Technology Regulating Resource (“ATRR”), and
- DRR.

³³ For purposes of this discussion, a facility that interconnects with the electric system at a POI will be a facility that has little or no end-use customer load, such as a generating facility or an electric storage facility. A facility that interconnects with the electric system at a RDP will be an end-use customer facility.

The Compliance Proposal also includes two new DERA-specific participation models:

- Settlement Only Distributed Energy Resource Aggregation (“SODERA”), and
- Demand Response Distributed Energy Resource Aggregation (“DRDERA”).

Consistent with the requirements of Order No. 2222, all proposed participation models are technology neutral and allow a mix of technologies in the same aggregation. Each model includes technical, operational and performance requirements that are appropriate for the services being provided—for example, a DERA participating as an ATRR must be able to demonstrate and report changes in energy injected/withdrawn in four second intervals whereas a SODERA only needs to report hourly energy injections/withdrawals. A DERA participating in the New England Markets using a particular model will be viewed as the asset type associated with the model. For example, a DERA using Generator Asset model will be subject to the rules for a Generator Asset; a DERA using CSF model will be subject to the rules for a CSF; a DERA using DRDERA model will be subject to the rules for a DRDERA; and so on.

The requirements for participation as a DERA in the energy and ancillary services markets are mostly contained in Section III.6 of the Tariff. Additional changes are included throughout Section III.1.10.1A of the Tariff in order to accommodate Energy Market offers made by DERAs, as well as numerous subsections of Sections III.1-12 and III.14 in order to integrate DERAs into the existing market structures. A complete list of these sections is contained in Appendix A to this filing.

Each participation model is discussed in turn below. The first five participation models leverage existing, Commission-approved participation models with either minor, or no modifications; the latter two are new models specifically proposed in order to comply with Order No. 2222. The additions in Section III.6.1 allow DERAs to use these existing or new models to participate in the energy and ancillary services markets. The Compliance Proposal at Section III.6.7(d)(3) allows DERs participating in a DERA to provide both retail and wholesale services to the extent such dual participation is allowed under state law or regulation, and so long as the DERA is able to comply with all of the relevant requirements for the services provided under the Tariff.

a. Generator Asset Model

The Generator Asset model enables an aggregation of DERs with dispatchable energy injection capability to supply energy on a Day-Ahead and Real-Time basis, provide Operating Reserves and regulation products if it is technically capable of doing so. A DERA using the Generator Asset model will receive either Desired Dispatch Point (“DDP”) or Do Not Exceed (“DNE”) dispatch instruction³⁴ like other Generator Assets.

³⁴ DDP dispatchable Generator Assets are typically dispatchable in both the upwards and downwards directions, like a gas turbine. DNE dispatchable Generator Assets are typically dispatchable in the downwards direction only, like a wind generator.

The Generator Asset model is an existing model that currently allows participation by a single generator, or by relatively limited aggregations of several generators that comprise a single generating station, to participate in the energy and ancillary services markets. The Compliance Proposal at Section III.6.1(e) expands the existing Generation Asset model to accommodate an aggregation of DERs.

b. CSF/BSF Models

The CSF and BSF models, as originally designed, accommodate Electric Storage Facilities. In particular, the CSF model was developed for very fast responding new storage technologies such as batteries, and the BSF model was developed to accommodate other storage technologies such as pumped-storage hydroelectric facilities. These models, which were accepted by the Commission prior to ISO-NE's compliance filing in response to Order No. 841, were further refined to comply with Order No. 841.³⁵ Further improvements to these models have been made to accommodate heterogeneous, co-located and hybrid facilities such as a combined PV and battery facility.³⁶

The CSF and BSF models³⁷ were designed for an individual storage or co-located generation/storage resource located at a single POI. Since all CSF and BSF facilities consist of both load and generation, and because the technologies comprising these facilities are fast responding such that the load and/or generation phase of the resource is able to provide Operating Reserves and potentially Regulation as well as energy withdrawal or injection, these models were particularly well-suited for modification to accommodate a heterogeneous aggregation of DERs. Thus, the Compliance Proposal through Section III.6.1(e) expands the existing CSF and BSF models to accommodate an aggregation of DERs that may or may not be storage resources but have similar physical and operational characteristics as the storage resources. Use of the CSF and BSF models will allow an aggregation of DERs with dispatchable energy injection capability, dispatchable energy withdrawal capability, and/or regulation capability to provide Day-Ahead or Real-Time energy services (as a supplier or a consumer), Operating Reserves, and/or regulation products simultaneously.

Further, under proposed Section III.6.1(e)(i) a DERA using the CSF or BSF models need not have any storage technologies in the aggregation to participate in the market using these models, which makes this approach technology neutral. This approach recognizes that a heterogeneous aggregation of loads and generation could together act like a storage device that withdraws energy when prices are low (or negative) and injects energy when prices are high, which

³⁵ See *ISO New England Inc. and New England Power Pool*, 166 FERC ¶ 61,146 (2019); *ISO New England Inc.*, 169 FERC ¶ 61,140 (2019); *ISO New England Inc.*, 172 FERC ¶ 61,125 (2020); and *ISO New England Inc. and New England Power Pool*, Docket No. ER19-470-005 (Feb. 10, 2021) (delegated letter order accepting Order No. 841 compliance filing).

³⁶ See *ISO New England Inc.*, Market Participation Options for Combined Intermittent/Electric Storage Facilities, <https://www.iso-ne.com/static-assets/documents/2020/04/20200408-co-located-market-participation.pdf>.

³⁷ Whether a resource chooses the CSF model or BSF model depends on whether the resource could seamlessly transition between energy injection and energy consumption. If it could, then it may use the CSF model; otherwise, it may use the BSF model. For example, in our current market, we see lithium ion batteries participating using the CSF model and pumped storage hydro-electric resources participating using the BSF model.

is exactly how an Electric Storage Facility behaves. The ISO expects that this approach will go far in promoting demand flexibility and responsiveness to prices, which will be particularly important as the generation fleet is decarbonized and sees higher penetrations of intermittent resources such as wind and solar resources.³⁸

c. ATRR Model

The ATRR model enables an aggregation of DERs with regulation capability to provide regulation products through the Regulation Market.³⁹ A DERA using the ATRR model must be able to follow the Automatic Generation Control (“AGC”) SetPoint.

The ATRR model is an existing model detailed in Section III.14 of the Tariff that allows small Regulation devices to aggregate together and participate as a single ATRR. However, the current rules require that such aggregations be at least one megawatt (“MW”) in size to participate in wholesale markets. To further facilitate DERA market participation, the Compliance Proposal reduces the minimum size requirement in Section III.14.2 of an ATRR from one MW to 100 kW, and adds a locational requirement to improve a DERA’s chances of being selected to provide regulation products.⁴⁰ The changes proposed to the existing ATRR model related to an aggregation’s size are discussed in the Size and Locations Requirements sections below.

³⁸ ISO-NE is considering changes to the CSF/BSF models to better accommodate co-located facilities that only inject energy into, but do not withdraw energy from, the grid (e.g., a battery that charges exclusively from on-site PV and not from the grid). If these changes are made, they would also apply to DERAs using these models, which would accommodate aggregations that behave similarly—e.g., that only inject or that only withdraw. These changes would be applicable to all users of the CSF/BSF models, not just DERAs, which necessitates a separate process outside of Order No. 2222 compliance process.

³⁹ The Regulation Market is addressed in Section III.14 of Market Rule 1. The regulation products procured through the Regulation Market include Regulation Service and Regulation Capacity.

⁴⁰ The regulation selection process considers transmission constraints, which prevents a resource from being selected to provide regulation if their sensitivity to a binding transmission constraint is above a threshold. In the case of a large and geographically dispersed ATRR, it may be that the ATRR has a sensitivity to many transmission constraints that may limit its ability to be selected to provide regulation. By limiting the geographical expanse of the ATRR, the locational requirement helps to ensure the ATRRs are only ruled ineligible for regulation when they have sensitivity to constraints in their local area.

d. DRR Model

The DRR model is an existing model that the Commission approved related to Order No. 745.⁴¹ The DRR model enables an aggregation of demand response DERs (referred to as “Demand Response Assets” in the Tariff) that have demand reduction capabilities to participate in the Day-Ahead and Real-Time Energy Markets, and provide Operating Reserves. Note that the existing DRR model pays the LMP for energy injected into the grid as a result of a Dispatch Instruction for the resource to reduce demand.⁴² To comply with Order No. 719, ISO-NE applies the “unit commitment” process, a process used for Generator Assets, to DRRs by modelling demand response as a proxy or virtual generator. This affords DRRs with specific benefits, such as the ability to specify a notification time, start-up time, minimum reduction time, minimum time between reductions (minimum down time), etc., in its Energy Market Offers, which are inter-temporal parameters comparable to those offered by Generator Assets.⁴³ The inter-temporal constraints specified by a DRR in its Energy Market offer would be honored in the dispatch algorithm.

The DRR model already accommodates aggregations as small as 100 kW, allows for aggregations as geographically wide as possible, is technology neutral (e.g., the demand reduction could be produced by reducing energy consumption, increasing behind-the-meter generation, or a combination of both), and enables an aggregation to provide all the services it is technically capable of providing, all of which are requirements under Order No. 2222. Therefore, the Compliance Proposal does not propose any changes to the DRR model.

⁴¹ The Commission largely accepted the ISO’s proposal to comply with Order No. 745 in the following orders: *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO’s Order No. 745 Compliance Filing); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-947-000 (April 17, 2012) (delegated letter order accepting the ISO’s Demand Response FCM Conforming Changes); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-1550-000 (May 29, 2012) (delegated letter order accepting the ISO’s Market Rule 1 Clarifications to the Transition Period Rules for Demand Response); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (order on the ISO’s Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); *ISO New England Inc.*, 144 FERC ¶ 61,140 (2013) (order on the ISO’s Market Rule 1 Clarifications to the Full Integration Rules for Demand Response and Revisions to Address the Treatment of Net Supply); *ISO New England Inc. and New England Power Pool*, Docket Nos. ER16-167-000 & ER16-167-001 (Dec. 23, 2015) (delegated letter order accepting delay of full integration of demand response into the wholesale markets by one year, until June 1, 2018); and *ISO New England Inc. and New England Power Pool*, Docket No. ER17-2164-000 (Oct. 17, 2017) (delegated letter order accepting revisions to implement full integration of demand response).

⁴² The energy injected by any of the Demand Response Assets comprising a DRR in response to ISO dispatch is called incremental Net Supply. For example, assume a Demand Response Asset that consumes 5 MW (and with a 5 MW adjusted baseline) and that has a 3 MW behind-the-meter generator. If this asset responds to ISO dispatch by (1) reducing consumption by 4 MW (i.e., consumption goes from 5 MW to 1 MW) and by (2) increasing generation by 3 MW, 2 MW of incremental Net Supply would be produced. Under the current ISO-NE rules, this resource would be paid for supplying 7 MW, the difference between its 5 MW adjusted baseline and the 2 MW of incremental Net Supply produced during the dispatch.

⁴³ See *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071, at PP 81, 84, and 89 (2008) (“Order No. 719”).

e. SODERA Model

The SODERA model is a new participation model proposed in the Compliance Proposal. The SODERA model, detailed in proposed Tariff Section III.6.6 enables an aggregation of DERs with non-dispatchable energy injection capability and/or non-dispatchable energy withdrawal capability to be paid for energy injected into the grid, or to be charged for energy withdrawn from the grid, at the LMP. A DERA using the SODERA model would not be dispatchable by the ISO and would not provide any telemetry data. It would therefore not be eligible to provide Operating Reserves or regulation products.

A SODERA is required to comply with all existing ISO-NE Market Rules applicable to Settlement Only Resources,⁴⁴ the rules applicable to DERAs in general, and those applicable to SODERAs in particular. The proposed rules allow a SODERA to submit a Supply Offer and/or Demand Bid in the Day-Ahead Energy Market in accordance with the requirements in Section III.1.10.1A(m). Enabling a SODERA to buy and sell energy at the day-ahead prices provides it a hedging tool against more volatile real-time prices.⁴⁵ It may also help improve day-ahead market price formation and converge day-ahead and real-time prices, which would achieve a more efficient day-ahead unit commitment schedule.⁴⁶

The Compliance Proposal also proposes conforming changes throughout Section III of the Tariff to incorporate the SODERA term so that certain rules and procedures are applied to SODERAs where appropriate.

f. DRDERA Model

The DRDERA model is a new participation model, detailed in proposed Section III.6.5 of the Compliance Proposal, which enables demand response DERs to aggregate with non-demand response DERs as required in Order Nos. 2222 and 2222-B. The DRDERA model allows an aggregation of DERs with demand reduction capability and energy injection capability to provide energy in the form of demand reduction or energy injection and to provide Operating Reserves. The model also allows the option for energy withdrawal capability to be part of the aggregation

⁴⁴ A Settlement Only Resource is a generating unit that is connected to the electric system at less than 115 kV, produces less than 5 MW and is entitled to receive capacity credit but is not centrally dispatched by the ISO control room and is not monitored in real time.

⁴⁵ Under current rules, Market Participants that are load-serving entities can submit Demand Bids into the Day-Ahead Energy Market, but Market Participants with Settlement Only Resources cannot submit Supply Offers into the Day-Ahead Energy Market. The Compliance Proposal extends Day-Ahead Supply Offer capability to the supply portion of a DERA participating in the market as a SODERA.

⁴⁶ The Commission has previously stated that improving price formation important to efficient market outcomes and to enable efficient investments by market participants. *See e.g. Settlement Intervals and Shortage Pricing in Markets Operated by Regnal Transmission Organizations and Independent System Operators*, 155 FERC ¶ 61,276 at P 5 (2016).

and be billed at the LMP for energy withdrawn.⁴⁷ The DRDERA model leverages the existing DRR model platform to ensure that demand response DERs are treated in accordance with Order Nos. 719 and 745. Additionally, the DRDERA model ensures the energy injection service and energy withdrawal service from the non-demand response DERs are treated in the same manner as for all other resources—that is, any energy injection (or energy withdrawal if included in the aggregation) is priced at the LMP and is compensated, even if the DRDERA is not dispatched by the ISO.⁴⁸

For a DRDERA, the ISO establishes a baseline for each DER in the aggregation in the same manner as prescribed for a Demand Response Asset in Section III.8.2 of the Tariff. The DER Aggregator is required to submit a Baseline Deviation Offer pursuant to Section III.1.10.1A(l) for unit commitment and economic dispatch purposes. The Baseline Deviation Offer reflects the aggregation’s ability to deviate from its normal operational level. The offer prices are subject to the Demand Reduction Threshold Price calculated pursuant to Section III.1.10.1A(f) to ensure energy payments for demand reductions satisfy the net benefits test described in the Order No. 745.⁴⁹

A Baseline Deviation Offer represents the physical and operational characteristics of the entire aggregation, which may include both demand response DERs and non-demand response DERs. A DRDERA is required to submit a single offer, rather than separate offers for demand response DERs and non-demand response DERs because the aggregation is treated as a single market resource.⁵⁰ Therefore, it is not possible to distinguish which part of the offer represents the demand response DERs component of the aggregation, and which part of the offer represents the non-demand response component. More importantly, it is not necessary to draw such distinction because, under the DRDERA model, all wholesale services are properly compensated. Demand reduction and Operating Reserves are treated in accordance with Order Nos. 745 and 719, while

⁴⁷ The Compliance Proposal recognizes that some Market Participants may have a business model to serve load, while others may not. Most of the load in New England is subject to retail customer choice, which allows non-utility load-serving entities to serve New England loads. To address this aspect of the New England market structure, the Compliance Proposal allows, but does not require, a Market Participant with a DERA consisting of Electric Storage Facilities or end-use customer facilities to serve the load of these facilities.

⁴⁸ For example, assume a DRDERA consisting of homes with dispatchable loads and roof-top PV generation. On a particularly sunny day, all of the PV generators are producing energy resulting in low LMPs. This results in none of the DRDERAs being dispatched. However, the roof-top PVs in the aggregation are producing more energy than the homes are consuming resulting in net energy injections. Under the current DRR rules, none of these energy injections would be paid as a supply of energy if the DRRs were not dispatched by the ISO. Under the new DRDERA rules, these energy injections would be paid the LMP as a supply of energy even though the DRDERA was not dispatched by the ISO.

⁴⁹ The application of the net benefits test only restricts a DRDERA to provide demand reduction service at or above the Demand Reduction Threshold price as required under Order No. 745. It imposes no restriction on when DRDERA can provide energy injection service or energy withdrawal service.

⁵⁰ Further, under the language proposed in Section III.1.10.1A(l), the Baseline Deviation Offer, which is consistent with the Demand Reduction Offers of DRRs and Supply Offers of Generator Assets, includes commitment parameters as part of the offer—e.g., Notification and Start-Up Times, Deviation (Interruption) Costs, Minimum Deviation Time, etc. These parameters are used in the unit commitment process. These commitment variables apply to the aggregated resource as a whole and not to individual components of a resource, and it is not possible to parse out different commitment variables for different components of a single resource.

energy injections and/or energy withdrawals are paid or billed at the LMP. The details regarding a DRDERA's Baseline Deviation Offer are contained in the Bidding Parameters section below.

When dispatched, a DRDERA will receive DDPs that reflect how many MWs it needs to deviate from its baseline. As a DRDERA performs to follow the DDPs, it may perform by providing demand reductions, energy injections, energy withdrawals, or a combination of these three services.

Under proposed Section III.6.5(d), the ISO will calculate a DRDERA's performance when it is dispatched. Performance will be calculated as the sum of the performance of each constituent DER in the aggregation in the same manner as prescribed for a Demand Response Asset in Section III.8.4. The performance of each DER in the DRDERA is accounted for in the form of demand reduction until the load of a DER is reduced to zero MW. If the load of that DER goes past zero showing an injection of energy into the grid, the amount of additional energy injected is settled at the applicable Real-Time LMP.

ISO-NE's current DRR participation model pays DRRs for any energy injections that are produced in response to ISO dispatch, but does not pay for any energy injections produced outside of ISO dispatch. In contrast, a DRDERA that injects energy outside of dispatch intervals will be settled at the applicable Real-Time LMP. This latter feature is unique to the DRDERA model.

g. Consistency With Compliance Requirements

The Filing Parties submit that the proposed participation models are consistent with the requirements of Order No. 2222. The models allow participation of behind-the-meter DERs and front-of-the-meter DERs in the same aggregation. As discussed in the section regarding metering below, the Compliance Proposal requires that services provided under these models be measured using metering located at a given DER's RDP or POI with the electric grid. The models do not

require DER Aggregators to be load serving entities unless the DERA includes wholesale energy withdrawal service.⁵¹

All participation models are designed to enable resources to provide one or more wholesale services regardless of the technology used to provide the services.⁵² For example, a battery, a distributed solar PV generator, an EV charger, and controllable thermostats and water heaters can be part of the same DERA. These different technologies bring different capabilities to the aggregation—the battery may have energy injection, energy withdrawal, and regulation capabilities; the solar PV generator may have energy injection capability; and the EV charger and controllable thermostats and water heaters may have demand reduction capability. For this type of heterogeneous aggregation, the DERA may use the DRDERA model and the ATRR model (as discussed above) so that all of its capabilities—i.e., energy injection, energy withdrawal, demand reduction, and regulation—can provide wholesale services that are properly sold (or billed as appropriate) through the New England Markets in the form of energy, demand reduction, Operating Reserves, Regulation, and capacity as applicable.

Further, each proposed participation model ensures that DERAs can provide all services currently sold in the ISO's markets, subject to the metering, telemetry, size and locational requirements discussed below. The Compliance Proposal does not create new wholesale services, or modify the services currently procured through the New England Markets. Order No. 2222 does not require that new market products be created to accommodate DERAs or that existing product requirements be modified in ways that would substantively redefine those products.

The Compliance Proposal allows Demand Response Assets, which the Commission considers to be DERs, to participate in aggregations through the existing DRR model or through the new DRDERA model. The new DRDERA model enables Demand Response Assets to

⁵¹ As the Commission is well aware, in New England, loads can be served by competitive retail suppliers. Thus, in New England, DER Aggregators are able to serve the aggregated loads of end-use customer facilities as well as for front-of-the-meter devices such as distribution-connected Electric Storage Facilities. DER Aggregators serving the loads of end-use customers would be encouraged to offer price-responsive services that promote demand flexibility such as increasing electric and thermal storage loads at times of low or negative LMPs as well as lowering loads at times of high LMPs. This proposal recognizes, however, that some DER Aggregators may make a business choice to not serve load and the Compliance Proposal accommodates their choice.

⁵² While the Compliance Proposal allows for heterogeneous combinations of technologies and capabilities in a single DERA, it does not allow for a single DERA to use multiple energy market participation models simultaneously (energy market participation models refer to all of the participation models discussed in this section except the ATRR model. ATRR model is a Regulation Market participation model. Compliance Proposal allows certain energy market participation models, specifically, the DRDERA model and DRR model, to be used concurrently with the ATRR model). Each participation model has a unique set of attributes such as the nature of the Energy Market Offer (including intertemporal parameters), which are used to determine commitment and dispatch decisions. For example, some of the DERs in a DERA cannot participate in the DRDERA model while others participate in the SODERA model given that a DRDERA submits Energy Market Offers and is subject to ISO dispatch, whereas a SODERA is a non-dispatchable resource. Also, a DERA using the DRDERA model submits offers consistent with that model and is subject to unit commitment and dispatch under that model. Other DERs in the same DERA cannot also participate under, as an example, the CSF model, which has a different set of offer parameters and is subject to different commitment and dispatch logic. Because each participation model allows for a unique set of offer parameters, it is not physically possible to have a single offer representing a DERA in which different DERs in the aggregation participate in different energy market participation models.

aggregate with non-demand response DERs—e.g., a distributed generator, a battery, or a thermal storage device, either in front of or behind the meter—while the existing DRR model only allows Demand Response Assets to aggregate with other Demand Response Assets.

ii. Forward Capacity Market (“FCM”)

a. Current FCM Participation Models

Resources participate in the FCM under one of three participation models currently provided for under Section III.13 of the Tariff: the Generating Capacity Resource model,⁵³ the Import Capacity Resource model and the Demand Capacity Resource model. The Demand Capacity Resource model has three sub-categories: the Active Demand Capacity Resource (“ADCR”) model (which includes Demand Response Resources), the On-Peak Demand Resource model, and the Seasonal Peak Demand Resource model⁵⁴—these latter two models, which collectively are referred to as passive Demand Capacity Resources, include primarily Energy Efficiency measures and passive load-reducing behind-the-meter generation such as roof-top PV.⁵⁵ Distribution system connected resources currently participate in the FCM using the Generating Capacity Resource model if the resources are in-front-of-the-meter and the Demand Capacity Resource model if the resources are behind-the-meter.

b. Proposal to Incorporate DERAs Into the FCM

To further enable distribution system connected resources to participate in the FCM, the Compliance Proposal contains a new FCM participation model in Section III.13: the Distributed Energy Capacity Resource (“DECR”). A DECR is an aggregation of DERAs in a single DRR

⁵³ Specific types of Generating Capacity Resources may participate in the FCM under special rules designed for Intermittent Power Resources (e.g., wind, solar, run-of-the-river hydroelectric), and Settlement Only Resources (e.g., non-dispatchable generators).

⁵⁴ On-Peak Demand Resources typically include measures that reduce net energy consumption during peak-period hours on a year-round basis such as lighting Energy Efficiency measures. Seasonal Peak Demand Resources typically include measures that reduce temperature-sensitive peak loads such as air conditioning Energy Efficiency measures.

⁵⁵ Order No. 2222 considers passive, load-reducing resources such as energy efficiency and load management, and passive, load-reducing behind-the-meter generation, as DERs. Section III.13 currently allows these DERs to participate in the FCM as an On-Peak Demand Resource or Seasonal Peak Demand Resource. Such DERs can participate individually or through an aggregation as long as the resource has a demand reduction value of 100 kW or larger. The DERs in such an aggregation must all be located in the same Load Zone, which cover a very wide geographic area—there are eight such zones in New England. Since these resources are designed to reduce load, are passive in that they cannot respond to dispatch, and do not provide telemetry, they cannot participate in the Energy Market as a supply resource or provide any ancillary services. Since these DERs can only provide capacity and since the current ISO Tariff permits these DERs to participate in the FCM, the current Tariff is already compliant with Order No. 2222 with respect to these DERs. The Compliance Proposal makes no changes to the On-Peak Demand Resource or Seasonal Peak Demand Resource rules.

Aggregation Zone.⁵⁶ The DECR model leverages the existing Generating Capacity Resource model and ADCR model rules to enable an aggregation of DERAs to provide capacity service as a capacity resource through the FCM. An aggregation of DERAs may participate as a DECR in the Forward Capacity Auction (“FCA”), substitution auction, and reconfiguration auction, and may also participate in bilateral transactions as a single capacity resource alongside and in competition with other capacity resources. The rules for DECRs are generally similar, or identical, to those used for Generating Capacity Resources and ADCRs because all facilities comprising a DECR would have the characteristics of either a Generating Capacity Resource or ADCR. The Compliance Proposal incorporates a number of DECR-specific rules that are necessary to address the fact that DECRs are likely to include a heterogeneous mix of technologies, in contrast to the existing FCM participation models. The DECR-specific rules that vary from existing rules include:

- Rules Related to Aggregations,
- Auction Offer Rules, and
- Qualification Rules.

Each of these DECR-specific rules are discussed below in turn.

c. Rules Related to Aggregations

SODERAs may not participate in a DECR along with dispatchable DERAs (“DDERAs”).⁵⁷ This is because a DECR composed of SODERAs is not required to offer into the Day-Ahead Energy Market and is not able to offer into the Real-Time Energy Market, while a DECR composed of DDERAs is required to offer into the Day-Ahead Energy Market and the Real-Time Energy Market at a level equal to the lesser of the DECR’s Capacity Supply Obligation (“CSO”) or its physical availability. This “must-offer” requirement applicable to DDERAs is identical to that applied to dispatchable Generating Capacity Resources (generating resources that are not Settlement Only Resources) under Section III.13.6.1.1.1, and to ADCRs (which are all composed of dispatchable DRRs) under Section III.13.6.1.5.1.

The Compliance Proposal further requires that DECRs consist only of aggregations of DDERAs or of SODERAs. A passive Demand Capacity Resource—i.e., On-Peak Demand Resources and Seasonal Peak Demand Resources – cannot be registered as part of a DECR. Both On-Peak Demand Resources and Seasonal Peak Demand Resources are capacity resources, so there is no reason to include these resources into a DECR to participate in the capacity market. Also, On-Peak Demand Resources and Seasonal Peak Demand Resources consisting of Energy Efficiency measures have different treatment in the FCM from other capacity resources, which

⁵⁶ Section III.13.1.4A of the Tariff requires that DECRs be within the same Capacity Zone. Capacity Zones are used in the FCM to differentiate capacity prices among broad transmission zones based on expected system topology. A DRR Aggregation Zone, which is used for Energy Market purposes, is always contained within a single Capacity Zone. Accordingly, the requirement that a DECR be in a single Capacity Zone does not place any additional locational requirements on the DERs or DERAs that may comprise a DECR.

⁵⁷ Dispatchable DERAs refer to DERAs using the Generator Asset model, CSF model, BSF model, DRR model, or DRDERA model.

requires that resources consisting of Energy Efficiency measures be segregated from other capacity resources.⁵⁸

Additionally, a facility with non-Energy Efficiency measures—such as behind-the-meter Distributed Generation and Load Management—that are part of an On-Peak Demand Resource or a Seasonal Peak Demand Resource may not be part of a DECR. This rule, detailed in Section III.13.1.4A is necessary to avoid double counting the same demand-reducing or energy-injecting capacity in two different resources. However, a facility with Energy Efficiency measures that are part of an On-Peak Demand Resource or Seasonal Peak Demand Resource may be part of a DECR, as long as the Energy Efficiency measures are not registered as part of the DECR. Energy Efficiency is unique in that a facility treated with Energy Efficiency measures permanently reduces its baseline energy consumption well before real-time. If that same facility then installs measures that can further reduce demand in response to dispatch, and/or inject energy into the electric system, the Compliance Proposal would allow these incremental demand reduction or energy injection capabilities to participate as part of a DECR.

d. FCM Offer and Bid Rules

Under the Compliance Proposal, a DECR will be permitted to submit supply offers and demand bids in all FCM-related auctions to acquire or shed a CSO, in the same way that all other types of capacity resources are permitted to do under Section III.13.2.3.2. However, a DECR is not listed as a resource that may submit a composite offer in these auctions because a DECR can aggregate DERAs that, taken together, have the ability to provide year-round capacity at least equal to their associated DECR's CSO. The composite offer provisions were designed to allow individual capacity resources, such as a large, bulk-power generator with higher capability in one season, to “aggregate” with other resources with more capability in the opposite season so that the composite resource provides year-round capacity. DECRs, on the other hand, are aggregations of DERAs, which in turn are aggregations of individual DERs. Given their inherent ability to aggregate different DERs and different DERAs into the same DECR,⁵⁹ extending the composite offer provisions to DECRs is unnecessary.

e. Qualification Rules

A DECR's demand reduction capability and energy injection capability can provide capacity in the FCM; therefore, a DECR's Qualified Capacity (“QC”) will be determined based on its ability to reduce demand and/or inject energy pursuant to Section III.13.1.4A.1.1. The QC of a new DECR is the sum of the QCs of each facility included in the DECR. The methodology to determine the QC for a new DECR incorporates a combination of the rules in the APCR model and Generating Capacity Resource model. These rules are contained in Sections III.13.1.4A.1.1.6 and III.13.1.4A.1.1.7. In general, the QC of facilities that include demand reduction capability

⁵⁸ On-Peak and Seasonal Peak Demand Resources consisting of Energy Efficiency measures are not subject to pay-for-performance obligations and settlement whereas other FCM resources are. *See ISO New England Inc.*, 174 FERC ¶ 61,252 (2021).

⁵⁹ The proposed design, which allows different types of DERAs to aggregate into a DECR, allows the Market Participant to create a DECR that is a “portfolio” of different resource types that, as an aggregation, can perform more consistently across a variety of system conditions.

will be determined in the same manner as for current ADCRs under Section III.13.1.4.1.1. Further, the QC of facilities with energy injection capability of less than one MW will also be determined in the same manner as for current ADCRs because exact details of each of the small facilities that will be recruited to be part of the aggregation may not be known at the time of qualification. Finally, the QC of facilities with net injection capability greater than or equal to 1 MW will be determined using the same approach as for current Generating Capacity Resources.

In addition, the nature of the qualification process, as well as the critical path schedule monitoring of a DECR that has taken on a CSO in the FCM, will depend on the sizes of the facilities in the DECR. These rules are contained in Sections III.13.1.4A.1.1.2.3, III.13.1.4A.1.1.2.4, and III.13.3.2. The processes applicable to larger facilities (such as industrial facilities) will be similar to those applied to larger generators, and smaller facilities (aggregations of small commercial or residential facilities) will use an approach that accounts for the fact that these aggregations are built out over time by signing up large numbers of small customers. This structure mirrors the qualification and critical path schedule monitoring rules currently employed for ADCRs in Sections III.13.1.4.1.1.2.4, III.13.1.4.1.1.2.5, and III.13.3.2. Using this same approach for DECRs is reasonable because, as with DECRs, ADCRs permit the aggregation of facilities with different sizes—from large industrial to small residential, and therefore serve as a reasonable template for the qualification and critical path schedule monitoring rules for DECRs.

iii. Auditing

The Compliance Proposal provides for participating DERAs to be subject to certain auditing requirements. The proposed auditing rules are consistent with, or identical, to those used for other resource types, which have been previously approved by the Commission.

A DERA that participates under the Generator Asset, CSF, BSF, or SODERA participation models and is comprised of DERs with the same technology type, i.e., a homogenous aggregation, will be audited under existing Generator Asset rules per the proposed revisions to Section III.1.5. Similarly, a DERA that participates under the Generator Asset, CSF, BSF or SODERA participation models and is comprised of DERs with different technology types, i.e., heterogeneous aggregation, will have a two-hour audit duration for Establish Claimed Capability Audits, Seasonal Claimed Capability Audits, and ISO-Initiated Claimed Capability. A two-hour audit duration for a heterogeneous aggregation is reasonable because the same audit duration is presently applied to electric storage resources and to PV resources, which are expected to be the dominant technology types in a heterogeneous aggregation. A DERA that participates under the DRR participation model will be audited under the existing DRR model rules per revisions at Section III.1.5.1.3.1. Rules for Seasonal DRDERA Audits are included at Section III.1.5.1.3.2, based largely on the rules for Seasonal DR Audits.

Existing auditing rules for intermittent, net-metered, or special qualifying facilities will apply to DERAs when aggregations comprise DERs with those technology types. Auditing rules for DRDERAs will follow existing rules for DRRs, which is appropriate because the performance of both DRDERAs and DRRs is calculated as a deviation from a baseline. In accordance with the existing auditing rules in Section III.1.5.2, DERAs may be subject to ISO-initiated parameter auditing when such audits are called for under the existing rules.

DECRs will be subject to seasonal audit requirements pursuant to Section III.13.6.1.7.3. The Seasonal Audit Value of a DECR is the sum of the Seasonal Capabilities of DERAs comprising the DECR. There will be a Summer Seasonal Audit Value and Winter Seasonal Audit Value assessed during a year per Section III.1.7.13.

iv. Revisions to Rules for Resource Adequacy and Installed Capacity Requirement (“ICR”) Related Values

The Compliance Proposal includes rules that explain how DECRs are accounted for in the calculation of the ICR and related resource adequacy values, specifically in Sections III.12.7.2, III.12.7.3 and III.12.9.2.4 of the Tariff. These modifications are necessary to recognize that the Qualified Capacity of Existing DECRs must be accounted for in the calculation of the ICR and related values. Thus, as with all other capacity resource types, the calculation of the ICR, Local Sourcing Requirements, Maximum Capacity Limits, and Marginal Reliability Impact will account for the Qualified Capacity of Existing DECRs for the Capacity Commitment Period (“CCP”) for which the ICR and related values are being calculated.

3. *Order No. 2222 Directive: Size Requirements*

Order No. 2222 required that RTOs/ISOs set a minimum size requirement for DERAs no higher than 100 kW.⁶⁰ The Commission also provided flexibility for RTOs/ISOs to set maximum size limits for individual DERs as appropriate for their individual regions, which the Commission stated “would ensure that larger resources are required to participate individually, thereby allowing RTOs/ISOs to independently model and verify the metering of these larger resources.”⁶¹ The Commission declined to require RTOs and ISOs to set a minimum size requirement for individual DERs, but noted that DER Aggregators:

“[A]s market-interfacing entities, are responsible for meeting applicable RTO/ISO qualification and performance requirements, including minimum size requirements, and for determining how any performance penalties or deratings determined by the RTO/ISO would apply to the individual resources in an aggregation.”⁶²

The Compliance Proposal incorporates the Commission’s 100 kW minimum size requirement for DERAs as a requirement for participation, as detailed in Section III.6.1. The Compliance Proposal also proposes certain size requirements and limitations for individual DERs participating in a DERA based on technical and market considerations. These are detailed in Sections III.6.3 and III.14.2. The proposed size requirements and limitations are a reasonable exercise of the flexibility granted by the Commission and are related primarily to the location of the individual DERs comprising a DERA with respect to transmission nodes—for example a 12 MW DERA with all of its DERs located at the same transmission node would likely cause

⁶⁰ Order No. 2222 at P 171.

⁶¹ *Id.* at P 181.

⁶² *Id.* at P 180.

congestion issues while a 12 MW DERA with all of its DERs located at different transmission nodes within the same DRR Aggregation Zone would likely not cause similar issues.

For all DERA participation models, a DER with an energy injection capability of five MW or greater will be restricted from aggregating with other DERs and must participate as a single resource aggregation. If a group of DERs can inject five MW or greater at a single bus-level transmission node, that group is similarly restricted from aggregating with facilities at other nodes as the impact of that group at that node would be similar to that of a single, similarly-sized facility at that node. The DERAs in these two categories will be modeled and priced at the single bus-level transmission node. A DER is otherwise free to aggregate with other DERs that meet the locational requirements discussed in the next section. Such a DERA will be modeled and priced at the DRR Aggregation Zone pricing node.

With respect to the new SODERA model, in addition to the limits described above, each participating DER with energy injection capability participating as part of a SODERA must be eligible to be a SOR under the Tariff and relevant Operating Procedures, including, but not limited to OP-14.⁶³

With respect to the new DRDERA model, the “five MW or greater” size threshold stated in the general rule applies to an individual DER’s Maximum Deviation Capability that includes both the ability to reduce demand and to inject energy. Further, pursuant to proposed Section III.6.5(b) an individual DER with a Maximum Deviation Capability or ability to inject greater than or equal to five MW may not be registered as a component of a DRDERA if its maximum energy injection capability is greater than its Maximum Facility Load and such a DER must be the only facility associated with a DRDERA, which would be modeled and priced at a bus-level transmission node.

Finally, the Compliance Proposal includes a modification to the current ATRR size limits in Section III.14.2: a reduction from one MW to 100 kW, consistent with the requirement of Order No. 2222. ATRRs can currently aggregate individual facilities in order to meet the minimum size requirement, and that practice will continue under the new rules.

4. Order No. 2222 Directive: Locational Requirements

Order No. 2222 required that each RTO/ISO revise its tariff to establish locational requirements for DERs participating in a DERA, and stated that such requirements should be “as geographically broad as technically feasible.”⁶⁴ This could include either single-, or multi-node aggregations depending on the individual circumstances of each RTO/ISO. The Commission required that each RTO/ISO provide a detailed, technical explanation for its proposed geographical

⁶³ A SOR is a generating unit interconnected at a voltage less than 115 kV that produces less than 5 MW and is entitled to receive capacity credit but is not centrally dispatched by the ISO control room and is not monitored in real time.

⁶⁴ Order No. 2222 at P 204.

scope, including a discussion of the “RTO/ISO’s system topology and regional congestion patterns, or any other factors that necessitate its proposed locational requirements.”⁶⁵

All DERAs are subject to the size requirements discussed in the previous section. Section III.6.2 of the Tariff revisions in the Compliance Proposal contains locational requirements for DERs participating in a DERA. These requirements are participation-model specific. For DERAs using the Generator Asset, SODERA, DRDERA, CSF and BSF models, the proposed Tariff language allows for aggregations within the same DRR Aggregation Zone and metering domain.

ISO-NE will leverage its existing DRR Aggregation Zone,⁶⁶ and metering domain constructs,⁶⁷ in order to allow broad geographic aggregation that may be spread across multiple bus-level transmission nodes while being modeled at a single pricing node. Using DRR Aggregation Zone structure will ensure that the clearing and dispatching of a DERA’s energy injections, energy withdrawals, and/or demand reductions does not jeopardize transmission system reliability. Using the metering domain construct will ensure that supply and demand reported by the Host Participant Meter Readers to the ISO for Energy Market settlement is accurate.⁶⁸

For those DERAs using the DRR participating model, the existing DRR locational requirements apply, that is, aggregation would be allowed within the same DRR Aggregation

⁶⁵ *Id.*

⁶⁶ DRR Aggregation Zones represent areas in the ISO-NE system with minimum intra-zonal congestion, which were created to dispatch an aggregation of Demand Response Assets—such aggregations are defined as DRRs. There are currently 20 DRR Aggregation Zones in the New England Control Area. Using this zonal structure for the aggregation of DERs will ensure that the clearing and dispatching of a DERA’s energy injections, energy withdrawals, and/or demand reductions does not jeopardize transmission system reliability. The DRR Aggregation Zones represent the widest possible geographic area for DERAs because if the area were any larger it would increase the likelihood that DERs within the same DERA are on opposite sides of the same transmission constraint, which introduces the potential for conflicting impacts on that constraint. Dispatching a DERA without a clear picture of its impact on transmission constraints could put reliability of the transmission system at risk.

⁶⁷ Metering domains in New England generally follow a distribution utility’s service territory within a single Load Zone. As discussed in further detail in the section below regarding metering, Host Participant Meter Readers, are responsible for reporting energy settlement quantities to the ISO such that supply and demand in the metering domain are equal in each interval. Distribution utilities are assigned the Host Participant Meter Reader role in New England.

⁶⁸ If a DERA that has energy injections and/or withdrawals that are in multiple metering domains, its generation/load would impact the supply/demand amounts in multiple metering domains. To ascertain a DERA’s Energy Market performance, the DERs within each metering domain that comprise the DERA would be reported by different Host Participant Meter Readers separately, which then must be added back together to determine the DERAs overall performance as a single resource. This would essentially segregate the DERs comprising the DERA into separate resources and would significantly complicate the meter reading and settlement processes, which defeats the purpose of aggregating DERs, which is to simplify the data reporting process and treat a DERA as a single resource.

Zone.⁶⁹ For those DERAs using the ATRR participation model, the Tariff revisions will similarly use the DRR Aggregation Zones described above to define aggregations of DERs providing regulation products. Limiting aggregations of DERs providing regulation products to DRR Aggregation Zones will minimize the likelihood of any congestion management issues, which could arise if DERs located on opposite sides of a constrained interface are part of the same aggregated ATRR.

5. Order No. 2222 Directive: Distribution Factors/Bidding Parameters

Order No. 2222 requires that where an RTO/ISO allows multi-node aggregations that it also revise its tariff to require that DER Aggregators provide the RTO/ISO “the total distributed energy resource aggregation response that would be *provided from each pricing node*, where applicable, when they initially register their aggregation and to update these distribution factors if they change” (emphasis added) and incorporate bidding parameters into proposed participation models as needed to account for the physical and operational characteristics of a given DERA.⁷⁰

The locational approach described in the previous section, i.e. requiring that all DERs in a DERA be located in the same DRR Aggregation Zone does not require the submission of distribution factors by a DER Aggregator. The ISO calculates the distribution factors to allocate energy injection or dispatched demand reductions from DERAs across the DRR Aggregation Zone, making it unnecessary for the DER Aggregator to submit such factors.⁷¹ This approach allows for multi-nodal aggregations in the physical sense (i.e., DERs connected at different bus-level transmission nodes in a DRR Aggregation Zone may be allowed to aggregate, implying a multi-nodal approach), but the DRR Aggregation Zone itself is modelled as a single pricing node in the ISO-NE market model, which makes the submission of distribution factors unnecessary as all of the DERs comprising a DERA are offered, dispatched, and settled at the same pricing node.

The Compliance Proposal incorporates bidding parameter requirements for all DERA participation models as required by Order No. 2222. For DERAs using existing participation models, the required bidding parameters are the same as for those resources already using the model. For DERAs, these the parameters would apply to the DERA as a whole rather than to a

⁶⁹ Energy injections and withdrawals produced by DERAs using the Generator Asset, SODERA, DRDERA, CSF and BSF participation models will be settled through the Energy Markets such that the amount of energy supplied and consumed (adjusted for losses) in each metering domain and in each interval are equal. In contrast, demand reductions produced by DRRs and DRDERAs, and the regulation products provided by ATRRs are not settled through the Energy Market and do not affect the energy supply/demand balance in a metering domain, which allows DRR and ATRR aggregations to not be constrained by metering domain boundaries.

⁷⁰ Order No. 2222 at P 225.

⁷¹ The ISO assumes that the response of a DERA is distributed among the various transmission nodes in a DRR Aggregation Zone in proportion to the load at each transmission node within the DRR Aggregation Zone. While only an estimate, to date the ISO has found this to be a workable solution to accommodating broad aggregations of Demand Response Assets comprising a DRR, and so the same approach is proposed here for Order No. 2222 implementation. The maximum size and locational requirements of DERs comprising a DERA as discussed above, in which a single DER of 5 MW or greater, or an aggregation of smaller DERs that are concentrated at a single transmission node in an amount greater than or equal to 5 MW, must participate in the market at the transmission node and not at the DRR Aggregation Zone, and helps mitigate any potential imprecision inherent in this approach.

single facility or resource, and must be updated based on operational realities on the distribution system as discussed below in the section on Operational Coordination. The bidding parameters for existing models, contained in Section III.1.10.1A were previously approved by the Commission and are used by market participants today.

The SODERA and DRDERA parameters leverage existing models and take into account the mix of different capabilities that the DERs in a DERA may potentially have. The Compliance Proposal specifies bidding parameters for DRDERAs and SODERAs, which are contained in new additions to the Tariff in Sections III.1.10.1A(l) and III.1.10.1A(m) respectively.

Under Section III.1.10.1A(l), a DRDERA may submit a Baseline Deviation Offer for the supply of energy or demand reduction for each Operating Day, which constitutes an offer to submit the DRDERA to the ISO for commitment and dispatch. The offer must specify the Blocks (price and quantity pairs) for each hour of the Operating Day, but may not specify a price that is below the Demand Reduction Threshold Price, to satisfy the net benefits test in effect for the Operating Day.⁷² The offer may specify a Deviation Cost for each hour of the Operating Day, which may vary on an hourly basis. The offer must also specify a Minimum Deviation Time to be used for scheduling purposes that does not exceed 24 hours and a Maximum Deviation amount no greater than the sum of the Maximum Deviation Capabilities of the DRDERA's operational DERs. Changes to the Maximum Deviation and Minimum Deviation from those submitted as part of the DRDERA's Offer Data must be made to reflect the physical operating characteristics and/or availability of the DRDERA.

The ISO-NE DRR model uses the ISO's current Energy Market and Operating Reserve designation approach for Generator Assets. By using the same Energy Market platform as that used for Generator Assets, the ISO can commit and economically dispatch DRRs as an alternative to generation, which is required by Order No. 745. Since DRRs are integrated into Energy Market dispatch, and since Energy Market Offers are used in the Operating Reserve designation process, the ISO can also integrate DRRs along with Generator Assets in the provision of Operating Reserves as required by Order No. 719. Order No. 719 requires that the ISO allow DRRs the same ability to offer their intertemporal parameters as Generator Assets.⁷³ The Compliance Proposal extends these same features and capabilities to DRDERAs, ensuring that that the Compliance Proposal complies with the requirements of Order No. 2222 as well as Order Nos. 745 and 719.

Under Section III.1.10.1A(m), a SODERA may submit Supply Offers and/or Demand Bids, which will apply only to the Day-Ahead Energy Market. Such offers and/or bids must specify the Resource and Blocks (price and energy quantity pairs) for each hour of the Operating

⁷² Order No. 745 "requires the use of the net benefits test...to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources." Order No. 745 at P 3. ISO-NE implemented the net benefits test by requiring a DRR's offer price to be above the Demand Reduction Threshold Price. Since DRRs will be able to participate in the market using the DRDERA model, the Compliance Proposal applies the same net benefits test implementation method to the Baseline Deviation Offer, which will be used to commit and dispatch the DRDERA as a single resource. Further, the Baseline Deviation Offer is not to include average avoided peak transmission or distribution losses in the baseline deviation quantity as the ISO computes those quantities based on demand reductions delivered.

⁷³ Order No. 719 at PP 81, 84, 89.

Day for each Resource offered and/or bid by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis. These Supply Offers and/or Demand Bids would be used in the clearing of the Day-Ahead Energy Market, but would not be used in Real-Time dispatch as SODERAs will not be subject to ISO dispatch.

6. *Order No. 2222 Directive: Information & Data Requirements*

The Commission required RTOs/ISOs to establish information and data requirements with respect to the physical and operational characteristics of DERAs and their constituent DERs. Specifically, Order No. 2222 states that RTOs/ISOs must revise their tariffs to include requirements related to obtaining a list of DERs in each DERA, including necessary physical and operational information for individual resources; the provision of aggregate settlement data for each DERA; and the retention of data for individual DERs for auditing purposes.⁷⁴

i. DERA Registration

The Compliance Proposal includes new Section III.6.7 of the Tariff, which delineates the information and data that a DER Aggregator seeking to register a DERA must provide. The registration process includes three phases: (1) initial notification; (2) eligibility confirmation; and (3) registration and activation. Each phase is discussed in turn below. Overall, the Tariff revisions establish transparent requirements, clearly state the required information, and define the roles of the DER Aggregator, Host Utility, RERRA, and ISO-NE in each stage.

During the initial notification phase described in Section III.6.7(a) of the Compliance Proposal, the DER Aggregator must simultaneously notify the ISO and the Host Utility (or its agent) of its intent to register a DERA, at which time it must provide contact information and a general description of the DERA—location(s), size(s), technologies, planned markets, intended participation model, and desired target activation date. To submit an initial notification, each DER comprising the DERA must have an executed interconnection agreement, where state rules require the DER to have an interconnection agreement, or if an interconnection agreement is not required, the DER Aggregator must provide information needed to conduct any studies that may be necessary to identify distribution system impacts of the DERA. The DER Aggregator's initial notification triggers the 60-calendar day deadline for the Host Utility (or its agent) to review each DER for eligibility to participate in a DERA.

As further detailed in the Coordination section below, the Compliance Proposal requires Host Utilities (or their agents) to review each DER for relevant safety, reliability and eligibility criteria, including any RERRA-established criteria that may be put in place.

Following the Host Utility's (or its agent's) review, under Section III.6.7(c) if all DERs in a DERA are determined to be eligible, the ISO proceeds to finalize the registration. At this phase, the DER Aggregator confirms with the ISO and the Host Utility (or its agent) the finalized list of a DERA's constituent DERs; the DER Aggregator provides/confirms additional required details; and the Host Utility (or its agent) confirms "location" information to the ISO—specifically, that

⁷⁴ Order No. 2222 at P 236.

all DERs comprising the DERA are in the appropriate metering domain. If any or all DERs in a DERA are determined to be ineligible by the Host Utility (or its agent), the Host Utility (or its agent) must provide written notice to the ISO and the DER Aggregator describing the criteria that the DER did not meet.

A DERA may also be determined eligible by the Host Utility (or its agent), but subsequent findings/decisions by the ISO determine that the DERA cannot be registered. This could involve a determination by the ISO that, for example, not all DERs in a DERA are in the same DRR Aggregation Zone, or that the DERA includes large DERs with greater than five MW of capability that are not eligible for aggregation.

Once eligibility is confirmed by the Host Utility (or its agent), the DER Aggregator is required to provide both the ISO and the Host Utility (or its agent) with a desired activation date, and additional information to allow for its registration under Section III.6.7(d). This information includes standard registration information as required by the ISO New England Manuals, as well as an attestation stating that all participating DERs are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements; and that the DER Aggregator retains the rights to offer the individual DER for participation into the New England Markets. The DER Aggregator must also provide confirmation, in writing, to the ISO and Host Utility (or its agent) that all DERs in the DERA have been deemed eligible and that the required metering and telemetry is in place, to meet the ISO requirements for participation in the planned markets.

The ISO must receive confirmation from the Host Utility (or its agent) that the DER Aggregator has met all applicable requirements with respect to metering and telemetry to enable the Host Utility or Assigned Meter Reader to include the DERA's metering data in the appropriate Generator or Load Asset and metering domain.

ii. DECR Information Requirements

a. Background

The Compliance Proposal includes language throughout Section III.13 establishing information and data requirements for the qualification and participation of DECRs in the FCM. In general, these requirements are based on the current rules for other capacity resources that participate in the FCM. The DECR model requires that information and data, similar to that submitted by Generating Capacity Resources pursuant to Section III.13.1.1.2, be collected where participating DERs are capable of energy injection. For DECRs that include participating DERs capable of demand reduction, information and data similar to that submitted by ADCRs under Section III.13.1.4.1.1 is required. While the information and data collected for DECRs will be similar to that required of other capacity resources, there are a number of DECR-specific requirements that were developed to address the potentially heterogeneous nature of DECRs. The DECR-specific information requirements are included in:

- Show of Interest (“SOI”),

- Critical Path Schedule Information, and
- DECR Qualification Package.

Each of these DECR-specific information requirements are discussed below in turn.

b. Show of Interest

To participate in the FCA, a New DECR must provide a SOI form and a New DECR Qualification Package (“DECRRQP”) in accordance with the existing deadlines established for the FCA. The Compliance Proposal includes changes to Section III.13 requiring that the QC of a DECR be estimated based on the energy injection and/or demand reduction capabilities of each facility included in the DECR. These capabilities could be based on a generic representation of the facilities that will be recruited to join the aggregation, or on the specific facilities in the aggregation as specified in III.13.1.4A.1.1.1 of the Tariff. The CSO awarded to a DECR in the FCA depends directly on the DECR’s QC, which is based on the representation of the facilities in the New DECRRQP.

For each New DECR, the ISO will perform an analysis based on the information provided in the New DECR SOI Form and New DECRRQP to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period pursuant to Section III.13.1.4A.1.1.3.

c. Critical Path Schedule Information

A critical path schedule (“CPS”) is required for any new DECR. The CPS requirements of a new DECR, which is contained in Sections III.13.1.4A.1.1.2.4 and III.13.1.4A.1.1.2.3, follows the current CPS requirements of ADCRs, with one modification: the size threshold for DECRRs evaluates net injection and demand reduction while the ADCR model only evaluates demand reduction. This difference is due to the fact that DECRRs may have both energy injection capability and demand reduction capability based on the composition of their underlying DERAs. If the combined net injection and demand reduction of the facilities comprising a DECR are each less than five MW, the CPS requirements from Section III.13.1.4A.1.1.2.4 (applicable to similarly small facilities comprising an ADCR) will apply to the DECR. Otherwise, the CPS requirements from Section III.13.1.4A.1.1.2.3, (applicable to a facility in an ADCR with greater than or equal to five MW of capability) will apply to the DECR.

d. DECR Qualification Package

For each resource that a Project Sponsor seeks to offer in the FCA as a New DECR, the DER Aggregator—as the Project Sponsor—must submit a New DECRRQP no later than the New Capacity Qualification Deadline. The New DECRRQP follows the New Capacity Qualification Package of an ADCR, except in the cases where the DECR has facilities with net injection greater or equal to 1 MW and less than 5 MW as measured from the facility’s POI, in which case the specific facilities in the aggregation must be described and a Customer Acquisition Plan is not required. Further, in the case where an intermittent generating facility, such as wind, solar, or hydro, is included in the DECR, the claimed summer and winter Qualified Capacity of the facility

and supporting site-specific data must be provided consistent with the qualification requirements for Intermittent Power Resources. The New DECRQP must conform to the requirements of Section III.13.1.4A.1.1.2.

7. *Order No. 2222 Directive: Metering & Telemetry*

The Commission required that RTOs/ISOs “establish market rules that address metering and telemetry hardware and software requirements necessary for distributed energy resource aggregations to participate in RTO/ISO markets.”⁷⁵ Order No. 2222 provides RTO/ISOs flexibility with respect to these requirements, and states that RTOs/ISOs must explain in their respective compliance filings why their requirements are necessary and do not pose an undue burden for individual DER participation through an aggregation.⁷⁶ The Commission also stated that RTO/ISO proposals should rely on retail metering currently in place for DERs to the extent possible to avoid unnecessary costs, and that metering requirements should address double compensation concerns.⁷⁷

i. Metering of Resources and Loads in New England

Metering responsibility within ISO-NE is governed by the TOA and the Tariff. In New England, the responsibility for metering resources and loads that settle through the Energy Market rests with the PTOs. With respect to transmission-connected resources, TOA Section 3.06(a)(vii) requires that the PTOs:

“[P]rovide the ISO with the right to use a level of communications capacity...on its telecommunication assets and equipment attached to or associated with Transmission Facilities...in order to supply reliability-related data including meter, voice and data communications; continue to receive and send (for Regulation purposes) telemetry to and from existing generators and transmission substations; provide for the receipt of such information from generators and substations, and provide metering data and/or telemetry to the ISO...as reasonably necessary for the ISO to perform its obligations under this Agreement and the ISO OATT....”

Section 3.06(a)(x) requires that the PTOs “provide the ISO with revenue metering data or cause the ISO to be provided with such revenue metering data.”

⁷⁵ Order No. 2222 at P 262.

⁷⁶ *Id.*

⁷⁷ *Id.* at PP 264, 269.

The Host Participant or Host Utility,⁷⁸ or its Assigned Meter Reader,⁷⁹ are responsible under Section 5.2 of Manual M-28,⁸⁰ for: (1) reporting of interval energy quantities for Load Assets, Generator Assets, and Tie Line Assets; (2) reporting of meter reconciliation data for use in resettlement process for Load Assets, Tie-Line Assets, and Generator Assets; and (3) prompt reporting of any discovered metering, calculating, or reporting errors with respect to an asset to the ISO and the Market Participant(s) owning or having rights to the asset. The purpose of requiring revenue quality metering (“RQM”) is to settle wholesale market accurately; the purpose of requiring Real-Time telemetry is to provide the control room with the situational awareness needed to dispatch resources and balance the grid in every moment in real-time.

ii. Compliance Proposal

The Compliance Proposal incorporates in Section III.6.4 of the Tariff requirements for the metering and telemetry requirements for DERAs. The requirements are consistent with the requirements for other resources using the same participation models, or draw from those models in the case of the new DRDERA and SODERA models. They are also consistent with the ISO-NE metering arrangement discussed above and the requirements of Order No. 2222.

DERAs participating as a Generator Asset, CSF, BSF, DRR, or ATRR must comply with the metering and telemetry requirements currently associated with those models.⁸¹

DRDERAs must comply with the metering requirements for DRRs found in Section III.3.2.2 of the Tariff, with implementation details that are contained in ISO Operating Procedure No. 18.⁸² DRDERA metering for energy injection service and/or energy withdrawal service will be provided to the ISO for the aggregation as a whole; however, a DRDERA’s metering for demand reduction service will be at the individual DER level, consistent with current metering requirements for DRRs. In this way, five minute telemetry will be sent to the ISO to calculate the baseline and demand-reduction performance of each DER in the aggregation. This DER-specific method is consistent with the ISO’s treatment of individual Demand Response Assets (“DRA”)

⁷⁸ Defined in Tariff, Section I.2.2 as “a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering[.]”

⁷⁹ Defined in Tariff, Section I.2.2 as the entity that “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.” The Assigned Meter Reader is most often the distribution utility in a particular metering domain, but could also be an agent working on behalf of the distribution utility.

⁸⁰ ISO-NE Manual M-28, https://www.iso-ne.com/static-assets/documents/2020/08/manual_28_effective_rev62_2020_08_06.pdf.

⁸¹ The ISO is currently revising its Operating Procedures to clarify the telemetry requirements for all ATRRs, which will apply to DERAs participating as an ATRR (subject to the Commission’s acceptance of the Compliance Proposal). These changes will be subject to NEPOOL stakeholder review at the Reliability Committee.

⁸² ISO-NE Operating Procedure No. 18, https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op18/op18_rto_final.pdf.

that comprise a DRR, and is necessary as demand reduction and energy injection produced when a DRDERA is dispatched are measured for each DER.⁸³

SODERAs must comply with the metering requirements currently in place for Settlement Only Resources, and Load Assets if the SODERA is capable of energy withdrawal. SODERAs are required to provide RQM data for the aggregation as a whole for wholesale market settlement purposes. However, SODERAs are not required to provide telemetry as they are not dispatchable resources.

For DERA participation models other than the DRR and DRDERA model, individual DERs are required to meet all applicable state and Host Utility metering requirements.⁸⁴ These requirements may vary from state to state, allowing for flexibility across the ISO's footprint while reducing costs for meter readers, and ultimately, retail customers. Generally, the meter of a DER must be located at the POI or RDP to measure the amount of service—i.e., the amount of energy injection, energy withdrawal, regulation, or demand reduction—delivered to the electric system, the quantity of which is used to manage the grid in balancing supply and demand. With respect to the measurement of demand reductions provided by DRRs, the Commission previously found that “[m]easuring demand response at the retail delivery point allows ISO-NE to effectively manage the grid because this point accurately reflects the load's impact on the New England transmission system.”⁸⁵

The ISO intends that the Compliance Proposal, however, provides flexibility in Section III.6.4(e) of the Tariff, which allows a DER's interconnection point to be located behind a RDP to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration. In such a case, the DER's meter data must be reported such that its output or load does not impact the load reported for the RDP. This will ensure that retail metering is relied on to extent practical and that the services paid for in wholesale markets are in fact making it past the POI or RDP of the facility as applicable. This requirement is narrowly designed to prevent double counting of services. For example, if the production of a behind-the-meter generator were directly sub-metered, the same production would also reduce the load as measured at the RDP meter. Paying the behind-the-meter generator based on its directly sub-metered production while also billing the customer based on its lower RDP meter reading would result in the double counting of services, a result that the Commission ordered RTOs/ISOs to prevent.⁸⁶

⁸³ Further, DRRs are aggregations of DRAs. Should a baseline for a DRR be formed using historical meter data of its underlying DRAs, that baseline would become invalid over time as the DRAs comprising the DRR change. Since we expect that the DERs comprising a DRDERA will similarly change over time, using the same process as that used for DRRs, where baselines and performance are determined on a DRA-specific basis and summed to determine the aggregation's performance, is appropriate.

⁸⁴ Metering requirements for individual DRA in a DRR and individual DER in a DRDERA (demand reduction portion) are specified in the ISO's Tariff.

⁸⁵ See *ISO New England Inc.*, 139 FERC ¶ 61,116, at P 12 (2012).

⁸⁶ Order No. 2222 at P 161.

The proposed rules therefore allow, but do not require, sub-metering of individual DERs⁸⁷ where the Assigned Meter Reader is capable of reconstituting the load at the RDP, or parallel metering, so that the metered DER does not impact the reported load at the RDP.⁸⁸ This approach narrowly addresses double-counting concerns and ensures the integrity of wholesale markets.

The Commission stated a clear preference for the use of existing retail metering for DER participation to reduce transaction costs.⁸⁹ At present, the majority of retail metering in New England is located at the RDP, not at a sub-meter location.⁹⁰ To date advanced metering infrastructure (“AMI”) has not been widely deployed in New England. However, various advanced metering and “Grid Mod” efforts are underway in New England states at present. It is expected that in the next several years, Host Utilities may be able to support interval metering and timelier communication of RDP meter data for mass market residential and small commercial customers.⁹¹ Once these capabilities are established, Host Utilities may be better able to manage the growing number of DERs on their systems to ensure safety and the reliability of the distribution system, and the same metering infrastructure can be leveraged to support wholesale market participation.

8. *Order No. 2222 Directive: Coordination*

Order No. 2222 requires that RTOs/ISOs establish rules for coordination with the distribution utilities that will host aggregations, and with the RERRAs of those utilities.⁹² The Commission stated that these rules were necessary in order to accommodate “the substantial role of distribution utilities and state and local regulators in ensuring the safety and reliability of the distribution system.”⁹³

⁸⁷ Note that the majority of retail metering in New England is located at the RDP, not at a sub-meter location. Many states prohibit sub-metering, such as a landlord sub-metering individual tenants and charging them for electricity used, unless explicitly authorized by the retail regulator. Mandating sub-metering would be at odds with state regulatory constructs and could potentially lead to increased costs for retail customers.

⁸⁸ The implementation timeline for capabilities related to load reconstitution for sub-metered DERs behind a RDP remains speculative at this time.

⁸⁹ Order No. 2222 at P 269.

⁹⁰ Further, many states prohibit sub-metering, such as a landlord sub-metering individual tenants and charging them for electricity used, unless explicitly authorized by the retail regulator. Mandating submetering would be at odds with state regulatory constructs and could potentially lead to increased costs for retail customers.

⁹¹ The implementation timeline for capabilities related to load reconstitution for sub-metered loads behind a RDP remains speculative at this time.

⁹² *Id.* at P 278.

⁹³ *Id.* at P 279.

i. Coordination with Distribution Utilities

a. Registration Coordination

The Commission required RTOs/ISOs to incorporate into their respective tariffs a process for Host Utility review of the eligibility of DERs participating in a DERA, triggered by the DER Aggregator's initial notification. The Host Utility review should include an examination of whether each DER is capable of wholesale market participation (*e.g.*, the DER is not also participating in a retail program that prohibits wholesale market participation, has valid operating agreements, etc.), and whether the DER would pose risks to the reliable and safe operation of the distribution system.⁹⁴ Order No. 2222 extended flexibility for RTOs/ISOs to create a process appropriate for their regions.⁹⁵ The process, however, must be "transparent, [and] provide[] specific review criteria that the distribution utilities should use."⁹⁶ The Order further stated that the time period for the Host Utility's review should not exceed 60 days.⁹⁷

To address these directives, the Compliance Proposal incorporates in Section III.6.7 a detailed registration process that is transparent, sets expectations for all parties, was developed in concert with stakeholders to address all concerns (and was uncontested), and meets the Commission's 60-day review period deadline. The data required for this process is in line with the information and data requirements in the compliance directive.

While information and data requirements were discussed above, relevant specifically to coordination, the Compliance Proposal includes data requirements designed to allow for Host Utilities to apply specific technical screens for review of risks to the distribution system. These technical screens include analyzing the potential for a DER or a DERA to create issues related to overloads, voltage, stability, short circuit interrupting capability, flicker, equipment operation frequency coordination, and contingency analysis. The proposed Tariff provisions also contain requirements that DER Aggregators provide sufficient information about the DERs that comprise a given DERA to determine whether they are in compliance with existing Host Utility requirements and/or are participating in retail programs that may prohibit or limit a DER's participation in wholesale markets. The proposed Tariff language allows the Host Utility (or its agent) 60 days to conduct its review. Inaction on the part of the Host Utility will lead to the presumption that all DERs identified as part of the DERA are eligible to participate.

The Compliance Proposal also includes proposed Tariff language related to dispute resolution between DER Aggregators and DER owners, as well as between Host Utilities and DER Aggregators. Disputes between the ISO and DER Aggregators will be addressed under the ISO's current dispute resolution procedures pursuant to Section I.6. Disputes between DER owners and DER Aggregators are to be addressed in the manner established in the contract between those entities, or otherwise by a court of competent jurisdiction as applicable. Disputes between Host

⁹⁴ *Id.* at P 292.

⁹⁵ *Id.* at P 293.

⁹⁶ *Id.* at P 293.

⁹⁷ *Id.* at P 295.

Utilities and DER Aggregators will be addressed in a process established by the RERRA, if available, or if not available, in accordance with Section I.6 of the Tariff as all Host Utilities in New England and all DER Aggregators by virtue of their position as Market Participants would be subject to that section of the Tariff.

These provisions are designed to balance the interests of multiple states with different policies for DERs and DER participation in wholesale markets, as well as numerous Host Utilities with different state tariff requirements, infrastructure, resources, and operating requirements. The proposed registration process includes all elements required by the Commission. Additional implementation details will be included in ISO manuals, which will be subject to the NEPOOL stakeholder process. Including such technical details in manuals is consistent with the Commission's "rule of reason."

b. Operational Coordination

Order No. 2222 also requires that RTOs/ISOs "(1) establish a process for ongoing coordination, including operational coordination, that addresses data flows and communication among itself, the distributed energy resource aggregator, and the distribution utility; and (2) require the distributed energy resource aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages."⁹⁸ As part of this process, Host Utilities must also be allowed to override RTO/ISO dispatch where distribution system safety or reliability are at risk.

The Compliance Proposal includes provisions addressing ongoing operational coordination as required. Specifically, Section III.6.8 of the Tariff allows for Host Utilities to override ISO Dispatch Instructions in limited circumstances and provides a framework for communications pathways in both day-ahead and real-time for the reliable operation of aggregations. The framework allows for various implementation approaches amongst Host Utilities, each of which is likely to have different capabilities and potentially different RERRA requirements for their operations.

Section III.6.8 divides operational responsibilities between the DER Aggregator, the Host Utility and the ISO. DER Aggregators are required to operate individual DERs in a manner consistent with the limitations and operating orders established by the Host Utility, ensure available distribution service exists to operate those DERs consistent with its New England Market obligations, and account for any known limitations of the distribution system to which the DERs are connected in its Offer Data for the DERA, including restrictions that have been placed directly on the DERA by the Host Utility. DER Aggregators are also required to have a Designated Entity or Demand Designated Entity,⁹⁹ as applicable, for each of their DERAs. The ISO plans to specify additional operational coordination details, including the process for identification of a Designated

⁹⁸ Order No. 2222 at P 310.

⁹⁹ Pursuant to ISO Operating Procedure No. 14, *Technical Requirements for Generators, Demand Resources, Asset-Related Demands, and Alternative Technology Regulation Resources*, a Designated Entity or Demand Designated Entity is an entity designated by a Lead Market Participant that provides dispatch services from a single physical location for a Resource such as a Generator Asset or a DRR and is the single point of contact to receive, acknowledge receipt of, and implement ISO dispatch instructions and other relevant communications.

Entity or Demand Designated Energy will specified in the ISO-NE Operating Procedures, as such technical details are appropriately included in those documents.¹⁰⁰

Host Utilities are required to communicate to DER Aggregators conditions on the distribution system that result in actual or anticipated limitations on the operation of individual DERs or DERAs. They may also temporarily override the ISO's dispatch of a Distributed Energy Resource Aggregation in circumstances where needed to maintain the reliable and safe operation of the distribution system.¹⁰¹

The ISO is required to coordinate with the applicable Host Utility to avoid conflicting operational directives, which may include but is not limited to sharing Day-Ahead Energy Market results and Real-Time Dispatch Instructions.

ii. Coordination With RERRAs

In addition to the coordination with Host Utilities, the Commission required RTOs/ISOs to specify in their respective tariffs the role, if any, of RERRAs in coordinating the participation of DERs in a DERA.¹⁰² The Commission offered that the California Independent System Operator's tariff provisions related to RERRA involvement could serve as a guide for other ISOs/RTOs, and noted areas to be considered, which include developing interconnection agreements; local rules for data sharing; metering and telemetry; rules for multi-use (i.e., wholesale and retail) applications; and resolving disputes between DER Aggregators and Host Utilities.¹⁰³

The Compliance Proposal includes proposed Tariff language in Section III.6.7 that allows RERRAs to play a role in DER participation in a DERA. All six states within ISO-NE's footprint have state interconnection rules and requirements for DERs, and these interconnection procedures will be relied upon by the ISO to ensure reliable operation of individual DERs in a DERA. As noted above, the Tariff revisions proposed in the Compliance Proposal direct DER Aggregator/Host Utility disputes to the RERRAs to the extent they have applicable processes. In addition, the Tariff revisions require that the DER Aggregator share DERA registration data with RERRAs to the extent they request to receive such information. Also, as noted above, the DERA metering requirements rely on state-approved metering standards for individual DERs participating in a DERA.

¹⁰⁰ See, e.g. *Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271 at P 16 (2008) (stating that “instructions [and] guidelines . . . [that] guide internal operations” are appropriately placed in non-tariff materials such as business manuals).

¹⁰¹ Order No. 2222 at P 312 requires “each RTO/ISO to revise its tariff to apply any existing resource non-performance penalties to a distributed energy resource aggregation when the aggregation does not perform because a distribution utility overrides the RTO's/ISO's dispatch.” The Compliance Proposal complies with this requirement in Section III.6.8 (e), which states that “[f]ailure of a Distributed Energy Resource Aggregation to follow an ISO Dispatch Instruction due to a distribution utility override does not excuse the Distributed Energy Resource Aggregator from any applicable charges (including any penalties) to which the aggregator is subject under the terms of the Tariff.”

¹⁰² Order No 2222 at P 322.

¹⁰³ *Id.* at P 323.

ISO-NE has included RERRAs throughout the compliance development process, including meeting with the New England Conference of Public Utilities Commissioners (“NECPUC”) on a monthly basis over the course of 2021 and with individual state commissioners or commission staff as needed, and believes that the Compliance Proposal appropriately includes them in the DERA participation framework. The proposed Tariff language allows for RERRAs to play an active role in the participation of DERAs if they choose to, but does not mandate such participation for all RERRAs.

9. *Order No. 2222 Directive: Modifications to List of DERs in a DERA*

The Commission required that RTOs/ISOs establish a process for the addition or removal of individual DERs from a DERA without the need for the DER Aggregator to re-register or re-qualify the DERA for market participation. Further, the Commission stated that it “may be appropriate for each RTO/ISO to abbreviate the distribution utility’s review of modifications to the distributed energy resource aggregation,”¹⁰⁴ and that “to the extent that an RTO/ISO requires distributed energy resource aggregators to provide information on the physical or operational characteristics of its distributed energy resource aggregation...aggregators must update such information if any modification to the list of resources participating in the aggregation results in a change to the aggregation’s performance.”¹⁰⁵

The Compliance Proposal incorporates, in Section III.6.7(e), a process for modifying a DERA without the need for re-registration/qualification. Under this process, Host Utilities (or their agents) will have 60 days to review changes to a DERA under the same criteria used for initial registration. While any such review is in progress, there will be no pause in the DERA’s participation in New England Markets. While the Commission noted that this period could be less than the 60 days allowed for review of the initial composition of a DERA, the Compliance Proposal applies the same 60-day timeframe to modifications as well. Using the same 60-day time frame will afford the time, where necessary, for Host Utilities to restudy an entire DERA to determine whether such changes produce reliability impacts across the entire DERA footprint, i.e., whether the changes introduce interactions between DERs that were not present for the original DERA composition.

With respect to DECRs, as modifications are made to the underlying DERAs that make up a DECR, the DECR does not need to maintain the technology mix that was initially qualified and became commercial, consistent with the rules in Section III.13.3.8(d). Further, the rules allow for an Existing Generating Capacity Resource or Existing Demand Capacity Resource, which meet the Commission-accepted definitions and requirements associated with DECRs, to convert to an Existing DECR.

¹⁰⁴ *Id.* at P 336.

¹⁰⁵ *Id.* at P 338.

10. Order No. 2222 Directive: Market Participation Agreement

Order No. 2222 required that RTOs/ISOs “include a standard market participation agreement that defines the distributed energy resource aggregator’s role and responsibilities and its relationship with the RTO/ISO and that an aggregator is required to execute before it can participate in the RTO/ISO markets.”¹⁰⁶ The Commission also stated that this “agreement must include an attestation that the distributed energy resource aggregator’s aggregation is compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory.”¹⁰⁷ Finally, the Commission required “that the market participation agreements that the RTOs/ISOs include in their tariffs not limit the business models under which distributed energy resource aggregators can operate.”¹⁰⁸

The ISO’s current Market Participant Services Agreement (“MPSA”) is business model and technology neutral and is included as an attachment to the Tariff. Given the ISO’s approach to its Compliance Proposal, it is not necessary to modify the MPSA to achieve the Order No. 2222 compliance obligations. Instead, the Compliance Proposal contemplates that DERAs will function under the existing Asset and Resource models. Thus, DERs are included in the definition of Asset and DRDERA/SODERA are included in the definition of Resource to account for the new participation models. By making these changes, all requirements in the MPSA applicable to Assets and Resources will apply directly to DERs and DERAs. DER Aggregators, who will participate in wholesale markets with DERs and DERAs, must then execute this standard agreement to become Market Participants and to participate in the New England Markets.

The Compliance Proposal further requires in Section III.6.7(d)(i)(2) that DER Aggregators submit, at the time of registration of a DERA, “an attestation, in a form prescribed by the ISO, stating that all participating Distributed Energy Resources are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements, and that the Distributed Energy Resource Aggregator retains the rights to offer the individual Distributed Energy Resource in New England Markets.” This attestation will be developed and made available through the ISO website prior to the effective date proposed below.

11. Order No. 2222 Directive: Opt-in for Small Utilities

The Commission required that small utilities, those with less than 4 million MWh in sales in the previous fiscal year, be required to opt-in (through their RERRA) in order to host DERAs.¹⁰⁹

The ISO-NE Compliance Proposal includes as a criterion for eligibility in Section III.6.1 that a DERA “not be located in the metering domain of a Host Utility that distributed 4 million

¹⁰⁶ Order No. 2222, at P 352.

¹⁰⁷ *Id.*

¹⁰⁸ *Id.* at P 353.

¹⁰⁹ *Id.* at P 65.

MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such Host Utility to host Distributed Energy Resource Aggregations.”

The ISO intends to implement this opt-in provision in the same manner as the small utility opt-in for Demand Response Resource hosting, a process that has been effective in determining where DRRs are eligible to be hosted in New England.

12. Miscellaneous Matters

i. Interconnection

Order No. 2222 states that DERs participating in the wholesale market exclusively through a DERA are exempt from the ISO’s interconnection procedures¹¹⁰ and that such participation will not create a “first use” under Order Nos. 2003 and 2006.¹¹¹ However, the Commission did not expressly require that the ISO update its interconnection procedures to reflect this exception. Rather, it allowed RTOs/ISOs to modify their interconnection procedures if modifications were necessary to accomplish the intent of Order No. 2222.¹¹²

ISO-NE determined that in order to effectively carry out the intent of Order No. 2222, two limited amendments to the Small Generator Interconnection Procedure (“SGIP”) in Schedule 23 of Section II to the Tariff are necessary. These modifications, which are reflected in Section 1.1.1 of the SGIP, will provide certainty for DER developers, DER Aggregators, RERRAs, and the ISO. First, the Compliance Proposal incorporates the Commission’s stated exception—i.e., that DERs participating in wholesale markets exclusively through a DERA are exempt from the SGIP—as a new exception added to the current list of exceptions in Section 1.1.1. Specifically, Section 1.1.1 has been revised to state, in relevant part, that: “the SGIP and SGIA shall not apply to...(iv) a Distributed Energy Resource that will be participating in the wholesale market exclusively through a Distributed Energy Resource Aggregation.” This language is consistent with the Commission’s statement in Order No. 2222.

Second, the Compliance Proposal proposes to incorporate a pathway for DERs that intend to participate in the New England Markets through a single-resource DERA, to participate in the energy and ancillary services markets prior to the effective date of the full slate of DERA rules. To accomplish that, Section 1.1.1 would exempt the DERs that make up a single-resource DERA from the SGIP when they: secure a CSO as part of a DECR in a Capacity Commitment Period prior to the effective date of the Compliance Proposal’s energy market rules, but are located on a distribution feeder that would otherwise be subject to the SGIP as part of the Administered Transmission System. In order to utilize this exemption, the individual DER must: (1) have a valid state interconnection agreement in place and (2) have been reviewed by the ISO for reliability purposes under Section I.3.9 of the Tariff (to the extent required by that section).

¹¹⁰ *Id.* at P 90.

¹¹¹ *Id.* at P 93.

¹¹² *Id.* at P 104.

This addition is reasonable and will accomplish the purpose of Order No. 2222 by eliminating a barrier to market participation for these DERs. At present, a DER's location on the distribution system dictates whether it is subject to the ISO Interconnection Procedures for purposes of wholesale market participation. DERs interconnected to non-Commission jurisdictional feeders may participate in the energy and ancillary services markets under a state interconnection agreement prior to the effective date of the ISO's DERA rules. However, an identical DER that happens to be interconnected to a Commission jurisdictional feeder would be subject to the ISO's interconnection procedures. This proposed second exception, which will self-expire upon the effective date of the complete Compliance Proposal, will ensure consistent treatment among similarly situated DERs, regardless of the jurisdiction of their respective interconnection point, which will allow for a faster pathway to the wholesale market for these resources, without sacrificing reliability.¹¹³

ii. Conforming and Ministerial Changes

The Compliance Proposal also incorporates in the Tariff certain conforming and ministerial changes. Specifically, the proposal includes revisions necessary to move current Section III.6 to Section III.1.10.10. This relocation is intended to improve readability of the Tariff and has no impact any other Tariff provisions.

The proposal also includes changes in Section III.1.11.3(e), which contains the rules related to Do Not Exceed ("DNE") Dispatch. The proposed changes are necessary to incorporate DERAs into the DNE Dispatch framework, as applicable, and provide clarity to the rules as they apply to existing resources. These changes do not affect existing resources under DNE Dispatch, but will serve to further the aim of the Commission in Order No. 2222 by allowing DERAs to use the DNE Dispatch option for market participation where appropriate.

As part of the Order No. 2222 compliance effort, the ISO identified the need to make certain modifications to the Tariff rules on Financial Assurance, Net Commitment Period Compensation and Market Monitoring to account for DERAs. Those changes are not included in the Compliance Proposal. Such changes will be filed as conforming changes following Commission acceptance of the Compliance Proposal and prior to the effective date for the energy and ancillary service market rules.

IV. REQUESTED EFFECTIVE DATES

As stated above, the Commission did not mandate a specific effective date for all RTO/ISO compliance proposals and, instead, allowed each RTO/ISO to propose a reasonable effective date based on specific regional considerations and market structures.¹¹⁴

¹¹³ While a single-resource DERA would not be able to participate in the energy and ancillary services market as a DERA prior to the effective date of that portion of the Compliance Proposal's Tariff changes, it could participate in those markets as a Generator Asset or SOR pursuant to the current market rules.

¹¹⁴ Order No. 2222 at P 361.

The Filing Parties respectfully request two effective dates for the Tariff revisions contained in the Compliance Proposal. First, the Filing Parties request that the rules for DECR participation in the FCM, the SGIP amendments, and certain definition changes become effective **November 1, 2022**. This will allow for DECR participation in time for the eighteenth FCA (“FCA 18”) and certainty for DER developers with respect to interconnection jurisdiction going forward. FCA 18 is the first auction in which DECRs can reasonably participate as the process associated with seventeenth FCA is already underway. Allowing participation in the earliest possible FCA was requested by stakeholders during the compliance process. The specific sections that are proposed to be effective on this date are denoted in Appendix A to the transmittal letter.

Second, the Filing Parties request that the remainder of Tariff sections included in the Compliance Proposal be made effective on **November 1, 2026**, which is seven months before the FCA 18 Capacity Commitment Period begins. This date is reasonable in light of the implementation needs of the ISO, Transmission Owners, and Host Utilities. These needs include, but are not limited to, software development for the integration of DERAs into wholesale markets and operations systems, and most significantly, Host Utility development of systems and procedures to review the eligibility of DERs to participate in wholesale markets and to assess the safety and reliability impacts of DERs on the distribution system at the time of registration and for real-time operations. Further, it is likely that additional utilities will have deployed AMI by that time, which would further facilitate DERA participation in wholesale markets. This effective date will also allow RERRAs to conduct any necessary rulemaking processes to coordinate the participation of DERs in both retail and wholesale markets, to review Host Utility implementation plans to the extent necessary, and to allow for implementation of RERRA orders by Host Utilities.¹¹⁵

The two requested effective dates will allow for efficient integration of DERAs into the New England Markets. The Filing Parties respectfully request that the Commission accept the complete Compliance Proposal, without amendment or condition on or before **November 1, 2022**, to allow for the ISO to implement FCM specific rules in time to allow for DECR participation in FCA 18. Approval of the complete Compliance Proposal will provide Project Sponsors with a reasonable understanding of their rights and obligations in the energy and ancillary service markets when taking on a Capacity Supply Obligation in FCA 18 with DECRs comprised of DERAs.

Following these effective dates, ISO-NE will review DERA participation in these models, just as it does periodically with other participation models, and determine whether improvements or modifications are needed going forward.

¹¹⁵ This timeframe will also allow for the staging of other current high priority projects that are being implemented by the ISO in the same timeframe such as implementing new energy market infrastructure known as the next Generation Energy Market or “nGEM” project, modifying the electric storage resource participation model to account for state of charge and duration characteristics in the day-ahead energy market, removing the Minimum Offer Price Rule from the FCM, developing and implementing a new capacity accreditation process for resources participating in the FCM, and developing and implementing new day-ahead ancillary service products, among others.

V. STAKEHOLDER ENGAGEMENT AND THE NEPOOL PARTICIPANT PROCESSES

As part of its stakeholder outreach efforts that occurred in parallel with the NEPOOL Participant Processes, ISO-NE convened more than two dozen regular meetings with key partners and affected parties starting in 2020 and throughout 2021, including NECPUC, New England’s electric distribution companies, New England’s transmission owners, Host Participant Assigned Meter Readers, and prospective distributed energy resource aggregators. The ISO also convened approximately monthly meetings with an ad hoc working group of distribution system operators and ISO system operators to discuss operational coordination issues. The ISO expects these meetings to continue into the foreseeable future. These discussions were productive and assisted in the development and consideration of the Compliance Proposal through the stakeholder process.

The Tariff rules to implement the Compliance Proposal to Order No. 2222’s compliance directive were considered through the complete NEPOOL Participant Process and supported by the Participants Committee. As further detailed below, the Tariff revisions were considered separately by NEPOOL’s three standing Technical Committees.

1. NEPOOL Technical Committees’ Review

Starting in December 2020, the ISO began discussions with the NEPOOL Markets Committee. The majority of Tariff revisions that comprise the Compliance Proposal were vetted by that Committee. Indeed, it reviewed revisions in Sections I.2.2 and III. At its December 7–9, 2021 meeting, the Markets Committee voted to recommend a motion that the NEPOOL Participants Committee support of the Compliance Proposal, with a 71.11% vote in favor.¹¹⁶ At that meeting, the Markets Committee also considered seven Participant-sponsored amendments to the ISO’s Compliance Proposal, none of which were supported.¹¹⁷

At various meetings in 2021, the Transmission and Reliability Committees also considered aspects of the Compliance Proposal. The Transmission Committee vetted revisions to Sections I.2.2 and II. At its December 13, 2021 meeting, the Transmission Committee unanimously supported the proposed revisions under its review.¹¹⁸ The Reliability Committee considered revisions to Sections I.2.2, III.1.5, III.1.7.13, and III.12. At its December 14, 2021 meeting, the Reliability Committee unanimously supported the proposed revisions under its review.¹¹⁹

¹¹⁶ The result of the roll-call vote at the Markets Committee meeting was as follows: Generation Sector (16.7% in favor, 0% opposed, 1 abstention); Transmission Sector (16.7% in favor, 0% opposed, 0 abstentions); Supplier Sector (14.31% in favor, 2.39% opposed, 5 abstentions); Publicly Owned Entity Sector (16.7% in favor, 0% opposed, 0 abstentions); Alternative Resources Sector (6.7% in favor, 9.8% opposed, 2 abstentions); and End User Sector (0% in favor, 16.7% opposed, 1 abstention).

¹¹⁷ NEPOOL has indicated that it will file supplemental comments describing each amendment and the voting outcome for each amendment.

¹¹⁸ One abstention in each of the following Sectors was recorded: Alternatives Resources; End User; and Supplier.

¹¹⁹ The abstentions in the Reliability Committee were recorded in the following Sectors: 2 in the Generation Sector; 1 in the Transmission Sector; 5 in the Supplier Sector; and 2 in the Alternative Resources Sector.

2. NEPOOL Participants Committee's Review

Subsequent to the three Technical Committees' respective consideration, the NEPOOL Participants Committee, at its January 6, 2022 meeting, voted to support the ISO's Compliance Proposal. Specifically, the Participants Committee unanimously voted to support the Tariff revisions that the Transmission and Reliability Committees recommended.¹²⁰ With a 71.10% vote in favor, the Participants Committee voted to support the Markets Committee-recommended Tariff revisions.¹²¹ As a result, the Participants Committee supported the full set of Tariff revisions, i.e., the Compliance Proposal.

3. PTO AC Review

In addition to NEPOOL's consideration, the PTO AC voted unanimously and without abstentions to support the SGIP revisions and certain definition changes at its January 27, 2022 meeting.

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.¹²² However, the Study Revisions filed herein are not traditional "rates." Further, ISO-NE 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. Notwithstanding their request for waiver, the Filing Parties submit the additional information enumerated below in substantial compliance with relevant provisions of Section 35.13.

¹²⁰ The following Participants abstained: the Generation Group Member, Jericho Power LLC ("Jericho"), the Large RG Group Member, Voltus, Inc. ("Voltus"), Castleton Comm. Merchant Trading ("Castleton"), H.Q. Energy Services (U.S.) Inc. ("H.Q."), Shell Energy North America (US) ("Shell"), Acadia Center ("Acadia"), Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Mr. Michael Kuser, the Massachusetts Attorney General's Office ("MA AGO"), Natural Resources Defense Council ("NRD"), and Jupiter Power LLC ("Jupiter").

¹²¹ The following Participants objected: Jericho, Sunrun Inc., Centrica Bus. Solutions Optimize, Enel X North America, Inc., Maple Energy, Vermont Energy Investment Corp., Voltus, the Small LR Group Member, Castleton, H.Q., NRG Power Marketing, LLC, Acadia, CLF, EDF, Maine Public Advocate Office, MA AGO, NRDC, PowerOptions, Inc., and Jupiter. The following abstentions were recorded: Generation Group Member, ENGIE Energy Marketing NA, Large RG Group Member, Borrego Solar Systems Inc., CLEAResult Consulting, Inc., Brookfield Renew. Trading & Marketing, Clearway Power Marketing LLC, Consolidated Edison Energy Inc., DC Energy, LLC, Emera Energy Companies, Exelon Generation Company, Galt Power, Inc., LIPA, Shell, Tenaska Power Services Co., Associated Industries of Massachusetts, Harvard Dedicated Energy Limited, Mr. Kuser, The Energy Consortium.

¹²² 18 C.F.R. § 35.13 (2014).

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

- ◆ This transmittal letter;
- ◆ Marked Tariff sections reflecting the revisions comprising the Compliance Proposal including their respective effective dates;
- ◆ Clean Tariff sections incorporating the revisions comprising the Compliance Proposal; and,
- ◆ List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and others to whom a copy of this filing has been e-mailed.

35.13(b)(2) – As noted above, the Filing Parties request that certain of the Tariff Revisions become effective on November 1, 2022 and the remainder on November 1, 2026.

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-NE website at <https://www.iso-ne.com/participate/participant-asset-listings/>. A copy of this transmittal letter and the accompanying materials have also been sent electronically to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, to the New England Conference of Public Utilities Commissioners, and to the Executive Director of the New England States Committee on Electricity. In accordance with Commission rules and practice, there is no need for the Governance Participants or the other entities described above 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 in this filing is contained in Section VIII 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) - ISO-NE’s approval of these revisions is evidenced by this filing. These revisions reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

35.13(b)(7) - The Filing Parties have no 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.

VII. CONCLUSION

For the reasons stated herein, the Compliance Proposal is consistent with, and appropriately implements, the letter and intent of Order No. 2222. The Filing Parties request that the Commission accept the Compliance Proposal as filed herein, without modification or condition, with the requested effective dates in order for the ISO to begin preparations for the qualification of DECRs in FCA 18 and to begin implementation of the energy and ancillary services market participation models as expeditiously as possible.

Respectfully submitted,

By: /s/ Graham Jesmer
Graham Jesmer, Esq.
Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
(413) 535-4045

By: /s/ Michael J. Thompson
Michael J. Thompson, Esq.
Abraham F. Johns III, Esq.
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200

Counsel for ISO New England Inc.

By: /s/ Eric K. Runge
Eric K. Runge, Esq.
Rosendo Garza, Jr., Esq.
Day Pitney LLP
242 Trumbull Street
Hartford, CT 06103
(860) 275-0660

Counsel for New England Power Pool Participants
Committee

By: /s/ Mary E. Grover
Mary E. Grover, Esq.
Chair, PTO AC Legal Working Group Chair
c/o Eversource Energy
800 Boylston Street, P1700
Boston, MA 02199-8003

(617) 424-2105

Counsel for PTO Administrative Committee

Appendix A: Compliance Proposal Tariff Provision Effective Dates

<u>Effective Date</u>	<u>Sections</u>
November 1, 2022	<p><i>Section I.2.2 – Definitions</i> Asset, Claimed Capability Audit, Demand Response Distributed Energy Resource Aggregation, Distributed Energy Capacity Resource, Distributed Energy Resource, Distributed Energy Resource Aggregation, Distributed Energy Resource Aggregator, Existing Distributed Energy Capacity Resource, Lead Market Participant, New Capacity Offer, New Distributed Energy Capacity Resource, New Distributed Energy Capacity Resource Qualification Package, New Distributed Energy Capacity Resource Show of Interest Form, Resource, Settlement Only Distributed Energy Resource Aggregation</p> <p><i>Section II - Schedule 23 - Small Generator Interconnection Procedures</i> Section 1.1.1 – Applicability</p> <p><i>Section III.12 – Calculation of Capacity Requirements</i> III.12.7.2 – Capacity III.12.7.3 – Resource Availability III.12.9.2.4 – Other Modeling Assumptions</p> <p><i>Section III.13 – Forward Capacity Market</i> III.13.1.1 - New Generating Capacity Resources III.13.1.2 - Existing Generating Capacity Resources III.13.1.4A - Distributed Energy Capacity Resources III.13.1.4A.1 - Definition of New Distributed Energy Capacity Resources III.13.1.4A.2 - Definition of Existing Distributed Energy Capacity Resources III.13.1.6 - Self-Supplied FCA Resources III.13.2.3 - Conduct of the Forward Capacity Auction III.13.2.5 - Treatment of Specific Offer and Bid Types in the Forward Capacity Auction III.13.3.1 - Resources Subject to Critical Path Schedule Monitoring III.13.3.2 - Quarterly Critical Path Schedule Reports III.13.3.4 - Covering Capacity Supply Obligations III.13.3.8 - FCM Commercial Operation III.13.4.2 - Participation in Reconfiguration Auctions III.13.5.1 - Capacity Supply Obligation Bilaterals III.13.6.1 - Resources with Capacity Supply Obligations III.13.6.2 - Resources without a Capacity Supply Obligation III.13.6.4 - ISO Requests for Energy III.13.7.2 - Capacity Performance Payments III.13.7.5 - Charges to Market Participants with Capacity Load Obligations</p>
November 1, 2026	<p><i>Section I.2.2 – Definitions</i> All Remaining Definitions</p> <p><i>Section III.1-11 – Market Rule 1</i> III.1.5.1.1 – General Audit Requirements III.1.5.1.2 – Establish Claimed Capability Audit III.5.5.1.3 – Seasonal Claimed Capability Audits</p>

	<p> III.1.5.1.3.2 – Seasonal DRDERA Audits III.1.5.1.4 – ISO-Initiated Claimed Capability Audits III.1.5.2 – ISO-Initiated Parameter Auditing III.1.7.13 – Seasonal DECR Audit Value III.1.7.18 - Ramping III.1.7.19 - Real-Time Reserve Designation III.1.7.20 - Information and Operating Requirements III.1.9.1 - Offer and Bid Caps and Cost Verification for Offers and Bids III.1.10 - Scheduling III.1.10.1 - General III.1.10.1A(l) - Demand Response Distributed Energy Resource Aggregation Baseline Deviation Offers III.1.10.1A(m) - Settlement Only Distributed Energy Resource Aggregation Supply Offers and/or Demand Bids III.1.10.2 - Pool-Scheduled Resources III.1.10.3 - Self-Scheduled Resources III.1.10.9 - Hourly Scheduling III.1.10.10.2 - Day-Ahead and Real-Time Energy Market III.1.11.1 - Resource Output or Consumption and Demand Reduction III.1.11.3 - Dispatchable Resources III.2.4 - Adjustment for Rapid Response Pricing Assets III.2.5 - Calculation of Nodal Real-Time Prices III.2.6 - Calculation of Nodal Day-Ahead Prices III.2.7A - Calculation of Real-Time Reserve Clearing Prices III.3.2.1 - ISO Energy Market III.3.2.2 - Metering and Communication III.3.2.6 - Emergency Energy III.6 - Distributed Energy Resource Aggregations III.6.1 - Participation Requirements III.6.2 - Locational Requirements III.6.3 - Distributed Energy Resource Size Requirements III.6.4 - Metering and Telemetry Requirements III.6.5 - Additional Requirements For Demand Response Distributed Energy Resource Aggregations III.6.6 - Additional Requirements For Settlement Only Distributed Energy Resource Aggregations III.6.7 - Coordination of Registration and Modification III.6.8 - Operational Coordination III.9 - Forward Reserve Market III.10.2 - Real-Time Reserve Credits III.10.4.1 - Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources <i>Section III.14 – Regulation Market</i> III.14.2 - Regulation Market Eligibility </p>
--	--

Marked Tariff

Effective November 1, 2022

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation](#), [a Settlement Only Distributed Energy Resource Aggregation](#), 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, [or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation](#).

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.

Curtailed 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 Distributed Energy Resource Aggregation \(DRDERA\) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.](#)

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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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 [or Baseline Deviation 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 Measure 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 (MG TSA) 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), MG TSA 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 MWs.

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 MWs.

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 MWs.

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](#), ~~or~~ [New Distributed Energy 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 Distributed Energy Capacity Resource** is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.](#)

[**New Distributed Energy Capacity Resource Qualification Package** is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.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 Distributed Energy Capacity Resource Show of Interest Form** is described in Section III.13.1.4A.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 an 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, [a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation](#).

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 Distributed Energy Resource Aggregation \(SODERA\) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.](#)

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.

SCHEDULE 23

**SMALL GENERATOR
INTERCONNECTION PROCEDURES**

TABLE OF CONTENTS

Section 1. Application

- 1.1 Applicability
- 1.2 Pre-Application
- 1.3 Interconnection Request
- 1.4 Site Control
- 1.5 Queue Position
- 1.6 Procedures for Transition
- 1.7 Type of Interconnection Service
- 1.8 Withdrawal

Section 2. Fast Track Process

- 2.1 Applicability
- 2.2 Initial Review
- 2.3 Customer Options Meeting
- 2.4 Supplemental Review

Section 3. Study Process

- 3.1 Applicability
- 3.2 Scoping Meeting
- 3.3 Interconnection Feasibility Study
- 3.4 Interconnection System Impact Study
- 3.5 Interconnection Facilities Study

Section 4. Provisions that Apply to All Interconnection Requests

- 4.1 Reasonable Efforts
- 4.2 Disputes
- 4.3 Interconnection Metering
- 4.4 Commissioning
- 4.5 Confidentiality
- 4.6 Comparability
- 4.7 Record Retention
- 4.8 SGIA
- 4.9 Coordination with Affected Systems
- 4.10 Evaluation of a Small Generating Facility Interconnection Request

Attachment 1 – Glossary of Terms

Attachment 2 – Small Generator Interconnection Request

Attachment 3 – Certification Codes and Standards

Attachment 4 – Certification of Small Generator Equipment Packages

Attachment 5 – 10 kW Inverter Process

Attachment 6 – Interconnection Feasibility Study Agreement

Attachment 7 – Interconnection System Impact Study Agreement

Attachment 8 – Interconnection Facilities Study Agreement

EXHIBIT 1 - Small Generator Interconnection Agreement (SGIA)

SECTION 1. APPLICATION

1.1 Applicability

1.1.1 The Small Generator Interconnection Procedures (“SGIP”) and Small Generator Interconnection Agreement (“SGIA”) shall apply to Interconnection Requests, as defined in Attachment 1, pertaining to Small Generating Facilities, except that the SGIP and SGIA shall not apply to: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer’s site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; ~~or~~ (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility’s owner intent is to sell 100% of the Qualifying Facility’s output to its interconnected electric utility; or (iv) a Distributed Energy Resource that will be participating in the wholesale market exclusively through a Distributed Energy Resource Aggregation. In the event the SGIP and SGIA do not apply, the Interconnection Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections.

A Distributed Energy Resource reviewed as part of a Distributed Energy Capacity Resource that qualifies in any Forward Capacity Auction that takes place prior to the effective date of Section III.6 (Distributed Energy Resource Aggregations), shall not be subject to the SGIP, provided that: i) the Distributed Energy Resource meets the requirements of, and is included in the Distributed Energy Capacity Resource as a single-resource Distributed Energy Resource Aggregation, ii) the Distributed Energy Capacity Resource was qualified as a resource composed of one or more Distributed Energy Resource Aggregations that are each single-resource aggregations; iii) each underlying Distributed Energy Resource has a valid state interconnection agreement, and iv) each of the underlying Distributed Energy Resources has received approval from the ISO for a Proposed Plan Application pursuant to Section I.3.9 of the Tariff, if applicable. Each Distributed Energy Resource Aggregation in such a Distributed Energy Capacity Resource shall comply with all requirements of Section III.6 of the Tariff (Distributed Energy Resource Aggregations) following its effective date.

A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Interconnecting Transmission Owner’s Distribution System that is part of

the Administered Transmission System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) (solely as a Network Resource) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures. To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for the purposes of generator interconnections under this Schedule 23. Capitalized terms in Schedule 23 that are not defined in Attachment 1 or the body of these procedures shall have the meanings specified in Section I.2.2 of the Tariff.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to May 9, 2006.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the System Operator's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The System Operator shall respond within fifteen (15) Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects all ISOs/RTOs, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the SGIA.

1.2 Pre-Application

1.2.1 The System Operator shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The names, telephone numbers, and e-mail addresses of the System Operator's contact employees or offices shall be made available on the System Operator's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Administered Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The System Operator shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form to the System Operator along with a non-refundable fee of \$500 for a pre-application report on a proposed project at a specific site. Within two (2) Business Days of receiving the pre-application report request form, the System Operator shall provide a copy of the pre-application request form to the Interconnecting Transmission Owner. The System Operator in conjunction with the Interconnecting Transmission Owner shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within twenty (20) Business Days of receipt of the completed request form and payment of the \$500 fee. The pre-application report produced by the System Operator in conjunction with the Interconnecting Transmission Owner is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Administered Transmission System. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3 Using the information provided in the pre-application report request form in section 1.2.2., the System Operator in conjunction with the Interconnecting Transmission Owner will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. The selection by the System Operator in conjunction with the Interconnecting Transmission Owner does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. The Interconnecting Transmission Owner shall be responsible for determining whether the proposed Point of Interconnection is on a distribution facility that is subject to the Tariff. If the pre-application report request form seeks information about a Point of Interconnection that is on a distribution facility that is not subject to the Tariff, the Interconnection Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the System Operator or the Interconnecting Transmission Owner to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the System Operator in conjunction with the Interconnecting Transmission Owner cannot complete all or some of a pre-application report due to lack of available data, the System Operator in conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the System Operator in conjunction with the Interconnecting Transmission Owner shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

1.3.1 Initiating an Interconnection Request

To initiate and establish a valid Interconnection Request, the Interconnection Customer shall submit all of the following to the System Operator in the manner specified in the Interconnection Request contained in Attachment 2 to this SGIP: (i) the processing fee or deposit specified in the Interconnection Request, (ii)

a completed Interconnection Request in the form of Attachment 2, and (iii) documentation of Site Control in the form specified in Section 1.4 of this SGIP.

The Interconnection Customer must submit a separate Interconnection Request for each site. The Interconnection Customer must comply with the requirements specified in this Section 1.3.1 for each Interconnection Request even when more than one request is submitted for a single site.

1.3.2 Acknowledgement of Interconnection Request

The System Operator shall acknowledge receipt of the Interconnection Request within three (3) Business Days of receipt of the request and attach a copy of the Interconnection Request to the acknowledgement.

Within three (3) Business Days of receiving the Interconnection Request, the System Operator shall provide a copy of the Interconnection Request to the Interconnecting Transmission Owner. If such request is to interconnect to a distribution facility, the Interconnecting Transmission Owner shall be responsible for determining whether the distribution facility is subject to the Tariff.

1.3.3 Deficiencies in Interconnection Request

An Interconnection Request will not be considered a valid request until all items in Section 1.3.1 have been received by the System Operator. If an Interconnection Request fails to meet the requirements set forth in Section 1.3.1, the System Operator shall notify the Interconnection Customer within ten (10) Business Days of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the System Operator the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 1.3.3 shall be treated in accordance with Section 1.8.

1.3.4 All fees or deposits that must be submitted to the System Operator under this SGIP, must be delivered to the System Operator's bank account by electronic transfer within the period specified in the respective provision. A deposit will not be considered received until it is in the System Operator's bank account.

1.4 Site Control

Documentation of site control must be submitted with the Interconnection Request. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a

modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. Site control may be demonstrated through:

1.4.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.4.2 An option to purchase or acquire an easement, a license or a leasehold interest in the site for such purpose; or

1.4.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose; or

1.4.4 Filed applications for required permits to site on federal or state property.

1.5 Queue Position

1.5.1 **General.** The System Operator shall assign a Queue Position based upon the date- and time-stamp of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of information on the application form in Attachment 2 to this SGIP, and Interconnection Customer provides such information in accordance with Section 1.3.3, then the System Operator shall assign Interconnection Customer a Queue Position based on the date the application form was originally submitted.

Except as otherwise provided in this Section 1.5, the Queue Position of each Interconnection Request will be used to determine: (i) the order of performing the Interconnection Studies; (ii) the order in which Interconnection Requests will be included in the CSIS and CFAC; (iii) the order in which Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service will be included in the CNR Group Study; and (iv) the cost responsibility for the Interconnection Facilities and upgrades necessary to accommodate the Interconnection Request. The System Operator shall maintain a single queue. At the System Operator's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

A CSIS and CFAC shall include the Interconnection Requests that were identified as eligible to participate in the CSIS and CFAC and met the associated requirements for inclusion in said studies in accordance with Section 1.5.3 of this SGIP. An Interconnection Request included in a cluster shall consider a higher queued Interconnection Request not included in the cluster. A lower queued Interconnection Request that is not included in the cluster shall consider all of the higher queued Interconnection Requests that are part of the cluster.

1.5.2 Order of Interconnection Requests in the CNR Group Study. Participation in a CNR Group Study shall be a prerequisite to achieve CNR Interconnection Service and CNI Interconnection Service. The CNR Group Study (to be conducted in accordance with Section III.13.1.1.2.3 of the Tariff) shall include all Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service that have an associated New Capacity Show of Interest Form that was submitted during the New Capacity Show of Interest Submission Window for the purpose of qualification for participation in the same Forward Capacity Auction for a Capacity Commitment Period, in accordance with Section III.13.1.1.2 of the Tariff, as well as Long Lead Facilities in accordance with Section 3.2.3 of Schedule 22 of Section II of the Tariff. Where a CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a lower Queue Position is associated with a New Capacity Show of Interest Form that was submitted for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and another CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a higher Queue Position is not associated with a New Capacity Show of Interest Form that was submitted for qualification until a subsequent Forward Capacity Auction, the CNR Interconnection Service or CNI Interconnection Service Interconnection Request with the lower Queue Position will be included in the CNR Group Study prior to the CNR Interconnection Service or the CNI Interconnection Service Interconnection Request with the higher Queue Position.

However, where an Interconnection Customer with a CNR Interconnection Service Interconnection Request submits a New Capacity Show of Interest Form for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and identifies in that New Capacity Show of Interest Form one or more Elective Transmission Upgrade Interconnection Request(s) for an Internal ETU that is not already included in the network model pursuant to Section III.12 of the Tariff for the particular Forward Capacity Auction, the CNR Interconnection Request will be included in the CNR Group Study at the lowest of the CNR Interconnection Request's or its associated Elective Transmission

Upgrade Interconnection Request(s) for the Internal ETU's Queue Position. Where multiple Interconnection Customers' CNR Interconnection Service Interconnection Requests are associated with the same lower Queue Position for an Elective Transmission Upgrade Interconnection Request for an Internal ETU in the CNR Group Study, the CNR Interconnection Request's Queue Position will be used as the tie breaker to dictate the relative order in which the CNR Interconnection Service Interconnection Request will be included in the CNR Group Study.

An Interconnection Customer with a Generating Facility or that is associated with an Import Capacity Resource in the case of an Elective Transmission Upgrade that is treated as a Conditional Qualified New Resource, in accordance with Section III.13.1.1.2.3(f) of the Tariff, may be responsible for the facilities and upgrades associated with an overlapping CNR Interconnection Service or CNI Interconnection Service Interconnection Request having a higher Queue Position if the Conditional Qualified New Resource obtains a Capacity Supply Obligation through a Forward Capacity Auction under Section III.13.2.5 of the Tariff.

An Interconnection Customer with a lower queued CNR Interconnection Service Interconnection Request for a Generating Facility or CNI Interconnection Service Interconnection Request for an Elective Transmission Upgrade that has achieved Commercial Operation and obtained CNR Interconnection Service or CNI Interconnection Service, respectively, may be responsible for additional facilities and upgrades if the related higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively. In such circumstance, Attachment 2 to the SGIA for the lower queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request shall specify the facilities and upgrades for which the Interconnection Customer shall be responsible if the higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively.

1.5.3 Clustering.

Clustering Interconnection Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable Regional System Plan in light of the New England Transmission System's capabilities for the time period under study. The System Operator may study an Interconnection Request serially to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Small Generating Facility.

1.5.3.1 Triggers for Studying Interconnection Requests in Clusters.

At the discretion of the System Operator, Interconnection Requests will be studied in clusters for the purpose of the Interconnection System Impact Study and the Interconnection Facilities Study when the combination of the following circumstances is present in the interconnection queue: (a) there are two (2) or more Interconnection Requests without completed Interconnection System Impact Studies in the same electrical part of the New England Control Area based on the requested Point of Interconnection, and (b) the System Operator has determined that none of the Interconnection Requests identified in (a) of this Section 1.5.3.1 will be able to interconnect, either individually or on a cluster basis, without the use of common significant new transmission line infrastructure rated at 115 kV AC or HVDC.

1.5.3.2 Notice of Initiation of Cluster Studies.

When the combination of the triggers specified in Section 1.5.3.1 of this SGIP are present in the interconnection queue, the System Operator will provide notice to the Planning Advisory Committee of the initiation of a cluster for studying certain Interconnection Requests under the Regional System Planning Process in accordance with Section 15.1 of Attachment K, Section II of the Tariff. The System Operator also will provide notice to the Interconnection Customers with Interconnection Requests identified in Section 1.5.3.1 of this SGIP, and at the time the System Operator notifies the Planning Advisory Committee of the initiation of a cluster, all study work for these Interconnection Requests will be suspended, and they will proceed under Section 1.5.3 of this SGIP. The System Operator will conduct Clustering in two phases. In the first phase, the System Operator will perform a CRPS to identify the CETU and associated system upgrades to enable the interconnection of potentially all of the resources proposed in the Interconnection Requests considered in Section 1.5.3.1 of this SGIP, consistent with Section 15.2 of Attachment K. In the second phase, the System Operator will conduct a CSIS and a CFAC to study the Interconnection Requests identified through the CRPS that have elected to participate in the CSIS together with the identified CETU and associated system upgrades, in accordance with this SGIP.

Within sixty (60) Calendar Days of the System Operator's notice to the Planning Advisory Committee of the initiation of the use of Clustering for studying certain Interconnection Requests under the Regional System Planning Process in accordance with Section 15.1 of Attachment K, Section II of the Tariff, Interconnection Customers with Interconnection Requests identified in Section 1.5.3.1 shall submit the technical data called for in Attachment 2 (including Attachment A, if applicable) to this SGIP to support the conduct of the CRPS.

1.5.3.3 Cluster Interconnection System Impact Study.

1.5.3.3.1 Notice of Cluster Interconnection System Impact Study Entry Deadline.

At the same time the System Operator issues the final CRPS report to the Planning Advisory Committee in accordance with Section 15.4 of Attachment K, the System Operator will provide notice of the entry deadline for the CSIS (the “Cluster Entry Deadline”) to the Interconnection Customers with Interconnection Requests identified in the final CRPS report as eligible to participate in the CSIS. The Cluster Entry Deadline shall be thirty (30) Calendar Days from the posting of the final CRPS report.

1.5.3.3.2 Cluster Interconnection System Impact Study Entry Requirements.

All Interconnection Requests identified in the final CRPS report, by Queue Position as assigned in accordance with Section 1.5.1 of this SGIP, shall be eligible to be studied together in the CSIS.

1.5.3.3.2.1 Cluster Entry Deadline Election. By the Cluster Entry Deadline, an Interconnection Customer with an Interconnection Request identified as eligible to be studied in the CSIS must, in writing:

- (i) withdraw the Interconnection Request, pursuant to Section 1.8;
- (ii) request that the System Operator re-assign the Interconnection Customer’s Interconnection Request a new Queue Position at the bottom of the queue as of the Cluster Entry Deadline in relative order with any other Interconnection Requests requesting to be re-queued under this Section 1.5.3.3.2.1; or
- (iii) request to be included in the CSIS and meet the CSIS entry requirements specified in Section 1.5.3.3.2.2.

If, by the Cluster Entry Deadline, Interconnection Customer fails to withdraw its Interconnection Request, request to be re-assigned a Queue Position at the bottom of the queue, or request to be included in the CSIS and meet the CSIS entry requirements, then the Interconnection Request will be automatically withdrawn from the interconnection queue as of the Cluster Entry Deadline without further opportunity to cure. If Interconnection Customer elects option (iii) and does not meet all of the CSIS entry requirements specified in Section 1.5.3.3.2.2 by the Cluster Entry Deadline, the Interconnection Request will be automatically withdrawn from the interconnection queue as of the Cluster Entry Deadline without further opportunity to cure. If an initial Cluster Participation Deposit had been submitted as part of the incomplete CSIS entry requirements submission, the initial Cluster Participation Deposit will be refunded at the time the Interconnection Request is withdrawn.

1.5.3.3.2.2. CSIS Entry Requirements.

An Interconnection Customer with an Interconnection Request identified in the final CRPS report as eligible to be studied in the CSIS that elects option (iii) under Section 1.5.3.3.2.1 must meet the following CSIS entry requirements in order to be included in the CSIS:

(1) Cluster System Impact Study Application. By the Cluster Entry Deadline, Interconnection Customer must submit to the System Operator, a completed Cluster System Impact Study Application in the form specified in Attachment 2, Attachment A-1 to this SGIP requesting the inclusion of the Interconnection Request in the CSIS;

(2) System Impact Study Agreement, Study Deposit, Technical Data, and Site Control. If an Interconnection Feasibility Study Agreement or an Interconnection System Impact Study Agreement has been executed prior to the issuance of the final CRPS report identifying the Interconnection Request as eligible for inclusion in a CSIS, such agreement shall terminate upon execution of a new Interconnection System Impact Study Agreement in accordance with this Section 1.5.3.3.2.2, and any unused balance of the study deposit associated with the terminated agreement shall be applied toward the study deposit associated with the new Interconnection System Impact Study Agreement.

Within fifteen (15) Business Days following the Cluster Entry Deadline, the System Operator and Interconnecting Transmission Owner will provide to Interconnection Customer an Interconnection System Impact Study Agreement, including a non-binding good faith estimate of the costs and timeframe for commencing and completing the CSIS.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the System Operator no later than thirty (30) Calendar Days after receipt along with continued demonstration of Site Control, the technical data called for in Attachment 2 (including Attachment A, if applicable), and a refundable study deposit, to the extent that any additional study deposit is required, in accordance with Section 3.4.2 of this SGIP.

(3) Cluster Participation Deposit. By the Cluster Entry Deadline, Interconnection Customer must also submit to the System Operator an initial Cluster Participation Deposit equal to five (5) percent of the

Interconnection Customer's cost allocation responsibility for the CETU and associated system upgrades to be determined based on the cost estimates provided in the final CRPS report. If the System Operator subsequently identifies that an Internal ETU has met the requirements to take the place of a CETU, or portion thereof, pursuant to Section 1.5.3.3.3.4 of this SGIP, the initial Cluster Participation Deposit will be reduced to exclude the costs associated with the CETU, or portion thereof, that is being replaced by the Internal ETU, and the Interconnection Customer shall be refunded the corresponding amount. Cost allocation of the CETU and associated upgrades shall be in accordance with Schedule 11, Section II of this Tariff.

The initial Cluster Participation Deposit will be fully refunded (with interest to be calculated in accordance with Section 1.8 of this SGIP) to Interconnection Customer with an Interconnection Request that met the cluster entry requirements: (i) if the cluster is initially undersubscribed by more than ten (10) percent of the quantity of megawatts that the CETU developed through the CRPS was designed to enable and the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 1.8, before the CSIS starts, (ii) if the CSIS is initially oversubscribed as described in Section 1.5.3.3.3.2 of this SGIP (e.g., the CETU developed through the CRPS is designed to enable 1,000 MW and more than 1,000 MW meet the CSIS entry requirements by the Cluster Entry Deadline), in which case the Cluster Participation Deposits will be refunded to Interconnection Customers with Interconnection Requests corresponding to the oversubscribed megawatt quantities, (iii) if the cost estimates for the CETU and the associated system upgrades provided in the final CRPS report for the entire cluster have increased by twenty-five (25) percent or more when compared to the cost estimates provided in the draft CSIS report or the draft CFAC report and the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 1.8, within thirty (30) Calendar Days after receipt of the draft CSIS report or the draft CFAC report in accordance with Section 3.4.5 and Section 3.5.4 of this SGIP, respectively, (iv) if less than two (2) Interconnection Requests included in the CSIS remain in the interconnection queue during the CSIS or CFAC, as applicable, in which case, the CSIS or the CFAC terminates and the remaining Interconnection Request proceeds in serial queue order, (v) at the time the Interconnection Customer with an Interconnection Request included in the CSIS provides to the Interconnecting Transmission Owner the deposit specified in Section 4.8 of this SGIP, (vi) if no Interconnection Customer with an Interconnection Request included in the cluster executes an Interconnection Agreement and provides to the Interconnecting Transmission Owner the deposit specified in Section 4.8 of this SGIP, or (vii) if all Interconnection Requests included in the cluster withdraw from the interconnection queue.

Otherwise, the initial Cluster Participation Deposit shall be non-refundable if the Interconnection Customer withdraws its Interconnection Request or the Interconnection Request is withdrawn from the interconnection queue at any time after the Cluster Entry Deadline. The non-refundable initial Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in a cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation.

1.5.3.3.3 Cluster Filling, Oversubscription and Backfilling Upon Withdrawal.

1.5.3.3.3.1 Cluster Filling. The CSIS shall be filled with all Interconnection Requests in the same electrical part of the New England Control Area relative to the CETU identified in the final CRPS report that do not yet have a completed Interconnection System Impact Study and met the CSIS entry requirements by the Cluster Entry Deadline up to the approximate megawatt quantity identified in the CRPS as potentially enabled by the CETU. The Interconnection Requests will be included in the CSIS in queue order, based on the Queue Positions assigned in accordance with Section 1.5.1 of this SGIP, relative to other eligible Interconnection Requests.

1.5.3.3.3.2 Cluster Oversubscription. If an Interconnection Customer with an Interconnection Request identified in the final CRPS report as eligible to participate in a CSIS met the CSIS entry requirements and therefore would have been eligible for inclusion in the CSIS but is excluded as a result of the quantity of megawatts identified as potentially enabled by the CETU in the final CRPS report having been exhausted in queue order under Section 1.5.3.3.3.1, (i) the Cluster Participation Deposit for the CSIS will be refunded to the Interconnection Customer, and (ii) the Interconnection Request will maintain its Queue Position. If there are two (2) or more Interconnection Requests after the CSIS is filled, the System Operator will initiate another cluster to identify the transmission infrastructure to enable the interconnection of another round of Interconnection Requests consistent with Section 15.1 of Attachment K.

1.5.3.3.3.3 Cluster Backfilling Upon Withdrawal. Upon withdrawal of an Interconnection Request that is included in the CSIS, the System Operator will backfill the CSIS, in queue order, with later-queued Interconnection Requests consistent with the methodology used to fill the original CSIS as specified in Section 1.5.3.3.3.1 of this SGIP. The System Operator will notify all Interconnection Customers with Interconnection Requests identified by the System Operator as eligible for backfilling that the respective Small Generating Facility (or part thereof) proposed in the Interconnection Request is eligible to

participate in the CSIS, and the Interconnection Customer shall have thirty (30) Calendar Days from receipt of System Operator's notice to withdraw its Interconnection Request, request to be re-assigned a Queue Position at the bottom of the queue, or accept the inclusion of the Interconnection Request (or part thereof, in which case the Interconnection Customer shall modify the Interconnection Request to reflect the appropriate reduction) in the CSIS and meet the CSIS entry requirements, consistent with Section 1.5.3.3.2 of this SGIP. If the Interconnection Customer does not make one of these three elections and complete the associated requirements by the thirtieth Calendar Day, the System Operator shall automatically withdraw the Interconnection Request from the interconnection queue without further opportunity to cure and consider other later-queued Interconnection Requests.

1.5.3.3.4 Scope of Cluster Interconnection System Impact Study. Except as otherwise provided in this Section 1.5.3.3.4, the CSIS shall be conducted in accordance with Sections 3.4.3 and 3.4.4 of this SGIP. The Study Case developed for the CSIS shall also include the CETU and associated system upgrades identified in the final CRPS report. An Internal ETU can be considered, and included in the CSIS, in place of a CETU, or portion thereof, if all of the Interconnection Customers with Interconnection Requests included in the cluster that the ISO has determined need to use the Internal ETU have indicated in the Cluster Application Form or with the executed Interconnection System Impact Study Agreement that they have a contractual commitment in place providing for the Interconnection Customers to fund and the right to use the Internal ETU. The CSIS shall evaluate the proposed interconnections to the New England Transmission System under the NC Interconnection Standard consistent with Section 1.7.2 of this SGIP and as detailed in the ISO New England Planning Procedures. Consistent with the NC Interconnection Standard, the evaluation will include conditions where the projects proposed in the Interconnection Requests that are included in the CSIS are not dispatched against each other if they do not share a system constraint that would provide the basis for a redispach condition. The CSIS shall consist of the analysis specified in Section 3.4.3 of this SGIP except for analysis associated with an Interconnection Feasibility Study or a preliminary, non-binding, analysis. An Interconnection Customer with an Interconnection Request being studied as part of the CSIS cannot elect to have the Interconnection Feasibility Study or a preliminary, non-binding, analysis performed as part of the CSIS.

1.5.3.3.5. Restudy of Cluster Interconnection System Impact Study. In addition to the circumstances specified in Section 3.4.6 of this SGIP, a re-study of the CSIS is required due to the withdrawal of an Interconnection Request that had been included in the CSIS. Upon withdrawal of an Interconnection Request that had been included in the CSIS, the System Operator will backfill the CSIS with eligible

Interconnection Requests pursuant to Section 1.5.3.3.3.3. A re-study will be conducted to determine if there are any changes in the upgrades identified during the CSIS with the exception of the CETU identified in the final CRPS report, which shall remain configured consistent with the megawatt quantity(ies) considered in the final CRPS report.

1.5.3.4. Cluster Interconnection Facilities Study.

Notwithstanding any other provision in this SGIP, an Interconnection Customer with an Interconnection Request included in a completed CSIS will not be eligible to waive the, or request a separate, CFAC. All Interconnection Customers with an Interconnection Request included in a completed CSIS shall be studied together in the CFAC for the purpose of implementing the conclusions of the CSIS with respect to non-sole use facilities.

1.5.3.4.1 Cluster Interconnection Facilities Study Entry Requirements.

An Interconnection Customer with an Interconnection Request that was included in a completed CSIS shall execute an Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to the System Operator, together with the required technical data and refundable deposit for the Interconnection Facilities Study as specified in Section 3.5.1 of this SGIP.

1.5.3.4.2. Scope of Interconnection Facilities Study. The CFAC will be conducted in accordance with Sections 3.5.2 and 3.5.3 of this SGIP based on a +/- 20 percent good faith cost estimate.

1.5.3.4.3 Re-study of the Interconnection Facilities Study. In addition to the circumstances specified in Section 3.5.5 of this SGIP, a re-study of the CFAC is required due to the withdrawal of an Interconnection Request that had been included in the CFAC. Upon withdrawal of an Interconnection Request included in the CFAC, the System Operator will backfill the CSIS with eligible Interconnection Requests pursuant to Section 1.5.3.3.3.3. A re-study of the CSIS and CFAC will be conducted to determine if there are any changes in the upgrades identified during the CSIS and CFAC with the exception of the CETU identified in the final CRPS report, which shall remain consistent with the megawatt quantity(ies) considered in the final CRPS report.

1.5.3.4.4 Additional Cluster Participation Deposit. Within thirty (30) Calendar Days after receipt of the final CFAC report in accordance with Section 3.5.3 of this SGIP, an Interconnection Customer with an Interconnection Request included in the CFAC shall submit to the System Operator an additional

Cluster Participation Deposit equal to five (5) percent of the Interconnection Customer's cost allocation responsibility for the CETU and associated system upgrades to be determined based on the cost estimates provided in the final CFAC report. Cost allocation of the CETU and associated upgrades shall be in accordance with Schedule 11, Section II of this Tariff.

The additional Cluster Participation Deposit provided under this Section 1.5.3.4.4 will be fully refunded (with interest to be calculated in accordance with Section 1.8 of this SGIP) to Interconnection Customer that submitted the additional Cluster Participation Deposit if the conditions specified in Sections 1.5.3.3.2.2(3)(v), (vi), or (vii) above occur.

Otherwise, the additional Cluster Participation Deposit shall be non-refundable if the Interconnection Customer withdraws its Interconnection Request or the Interconnection Request is withdrawn from the interconnection queue. The non-refundable additional Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in a cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation.

1.5.4 Transferability of Queue Position. An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change. The Interconnection Customer must notify the System Operator, in writing, of any transfers of Queue Position and must provide the System Operator with the transferee's contact information, and System Operator shall notify Interconnecting Transmission Owner and any Affected Parties of the same.

1.5.5 Modifications. Any modification to the Interconnection Request, including the information provided in the attachments, and to the machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the System Operator, in consultation with the Interconnecting Transmission Owner, and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the change are undertaken. An Interconnection Customer may decrease the electrical output of a proposed Small Generating Facility after the Cluster Entry Deadline specified in Section 1.5.3.3.1 of this SGIP; however, the requesting Interconnection Customer remains responsible for costs corresponding to the

megawatt quantity requested as of the Cluster Entry Deadline. A request to: (1) increase the energy capability or capacity capability output of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP shall require a new Interconnection Request for the incremental increase and such Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis; and (2) change from NR Interconnection Service to CNR Interconnection Service, at any time, shall require a new Interconnection Request for CNR Interconnection Service and such Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis.

Notwithstanding the foregoing, an Interconnection Customer with an Interconnection Request for CNR Interconnection Service has until the Forward Capacity Auction for which the associated Capacity Commitment Period begins less than seven (7) years from the date of the original Interconnection Request for CNR Interconnection Service to clear the entire megawatt amount for which the CNR Interconnection Service was requested (or as that amount has been modified in accordance with this Section 1.5.5). A new Interconnection Request for CNR Interconnection Service will be required for the Generating Facility to participate in any subsequent auctions.

1.6 Procedures for Transition

1.6.1 Queue Position for Pending Requests. Any Interconnection Customer assigned a Queue Position prior to November 1, 2017 shall retain that Queue Position subject to Section 1.6 of the SGIP.

1.6.1.1 If an Interconnection Study Agreement has not been executed prior to November 1, 2017, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with the version of this SGIP in effect on November 1, 2017 (or as revised thereafter).

1.6.1.2 If an Interconnection Study Agreement has been executed prior to November 1, 2017, such Interconnection Study shall be completed in accordance with the terms of such agreement.

If an Interconnection Study Agreement has been executed prior to November 1, 2017, but the Interconnection Study has not commenced, such Interconnection Study shall be completed, and any subsequent Interconnection Studies shall be processed, in accordance with the version of the SGIP in

effect on November 1, 2017. Interconnection Studies for Interconnection Requests seeking to interconnect into the Northern and Western Maine parts of the New England Control Area that do not have a completed Interconnection System Impact Study by November 1, 2017 shall be included in the Maine Resource Integration Study, which shall be the first CRPS. The Interconnection Customers identified in the Maine Resource Integration Study as eligible to participate in the associated Cluster System Impact Study shall make one of the elections and complete the associated requirements specified in Section 1.5.3.3.2 of this SGIP within thirty (30) Calendar Days from the later of November 1, 2017 or the final Maine Resource Integration Study report. If the Interconnection Customer does not make one of the elections and complete the associated requirements by the thirtieth Calendar Day, the System Operator shall automatically withdraw the Interconnection Request from the interconnection queue without further opportunity to cure.

1.6.2 Transition Period. To the extent necessary, the System Operator, Interconnection Customers with an outstanding Interconnection Request (i.e., an Interconnection Request for which an SGIA has neither been executed nor submitted to the Commission for approval prior to November 1, 2017), Interconnecting Transmission Owner and any other Affected Parties, shall transition to proceeding under the version of the SGIP in effect as of November 1, 2017 (or as revised thereafter) within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term “outstanding Interconnection Request” herein shall mean any Interconnection Request, on November 1, 2017: (i) that has been submitted, together with the required deposit and attachments, but not yet accepted by the System Operator; (ii) where the related SGIA has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding Interconnection Request as of the effective date of this SGIP may request a reasonable extension of the next applicable deadline if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension, not to exceed sixty (60) Calendar Days, shall be granted by the System Operator to the extent consistent with the intent and process provided for under this SGIP.

1.6.3 One-Time Election for CNR Interconnection Service at Queue Position Assigned Prior to February 1, 2009. An Interconnection Customer with an outstanding Interconnection Request will be

eligible to make a one-time election to be considered for CNR Interconnection Service at the Queue Position assigned prior to February 1, 2009. The Interconnection Customer's one-time election must be made by the end of the New Generating Capacity Show of Interest Submission Window for the fourth Forward Capacity Auction. Interconnection Customers requesting CNR Interconnection Service will be required to comply with the requirements for CNR Interconnection Service set forth in Section 1.7.1. Interconnection Customers requesting CNR Interconnection Service that have not received a completed Interconnection System Impact Study may request a preliminary, non-binding, analysis of potential upgrades that may be necessary for the fourth Forward Capacity Auction – the prompt or near-term auction – pursuant to Sections 3.3.2 or 3.4.3, whichever is applicable.

1.6.4 Grandfathering.

1.6.4.1 An Interconnection Customer's Generating Facility that is interconnected pursuant to an Interconnection Agreement executed or submitted to the Commission for approval prior to February 1, 2009, will maintain its status as a Network Resource with Network Resource Interconnection Service eligible to participate in the New England Markets, in accordance with the requirements of Market Rule 1, Section III of the Tariff, up to the megawatt amount specified in the Interconnection Agreement, subject to the Interconnection Customer satisfying all requirements set forth in the Interconnection Agreement and this SGIP. If the Generating Facility does not meet the criteria set forth in Section 1.6.4.3 of this SGIP, the Interconnection Customer will be eligible to make a one-time election, pursuant to Section 1.6.3, for Capacity Network Resource treatment without submitting a new Interconnection Request; however, the Interconnection Customer will be required to comply with the requirements for CNR Interconnection Service set forth in Section 1.7.1. Upon completion of the requirements to obtain CNR Interconnection Service, the Interconnection Customer's Interconnection Agreement shall be amended to conform to the SGIA in Exhibit 1 of this SGIP.

1.6.4.2 An Interconnection Customer's Generating Facility governed by an Interconnection Agreement either executed or filed with the Commission in unexecuted form prior to August 1, 2008, shall maintain the Queue Position assigned as of August 1, 2008, and be eligible to participate in the New England Markets, in accordance with the requirements in Market Rule 1, Section III of the Tariff, as in effect as of August 1, 2008, so long as the Interconnection Customer complies with all of the requirements specified in the Interconnection Agreement, including achieving the milestones associated with At-Risk Expenditures, subject to Section 1.5.5 of this SGIP.

1.6.4.3 All resources that are treated as Existing Generating Capacity Resources in the fourth Forward Capacity Auction pursuant to Section III.13 of the Tariff shall receive treatment as a CNR and obtain CNR Interconnection Service, in accordance with this SGIP, up to the CNR Capability of the resource. The grandfathered CNR Capability for these resources shall be equal to the megawatt amount established pursuant to the following hierarchy:

- (a) First, the megawatt amount specified in an Interconnection Agreement (whether executed or filed in unexecuted form with the Commission).
- (b) Second, in the absence of an Interconnection Agreement with a specified megawatt amount, the megawatt amount specified in an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision).
- (c) Third, in the absence of an Interconnection Agreement and an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision) with a specified megawatt amount, as determined by the System Operator based on the documented historic capability of the Generating Facility.

Where a resource has both an Interconnection Agreement and an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision), the lower megawatt amount will govern until the resource completes the applicable process(es) under the Tariff for obtaining the higher megawatt amount. The absence of an Interconnection Agreement or an approval pursuant to Section I.3.9 (or its predecessor provision) specifying a megawatt amount shall be confirmed by an affidavit executed by a corporate officer of the resource attesting that the resource does not have an Interconnection Agreement and/or an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision) that specifies a megawatt amount.

Where the governing document (as determined by the hierarchy set forth in 1.6.4.3) specifies a megawatt amount at an ambient temperature consistent with the definition of CNR Capability, the grandfathered CNR Capability shall be equal to that amount.

Where the governing document (as determined by the hierarchy set forth in Section 1.6.4.3) does not specify an ambient temperature, the megawatt amount will be deemed to be at the value consistent with the definition of CNR Capability.

Where the implementation of this Section 1.6.4.3 results in a CNR Capability that is different than previously had been identified, the revised CNR Capability will be applied commencing with the next Forward Capacity Auction qualification process (after the revised CNR Capability value is identified), which is initiated by the Show of Interest Window in accordance with Section III.13 of the Tariff. The revised CNR Capability will continue to govern until the resource completes the applicable process(es) for obtaining the higher megawatt amount.

1.6.4.4 All resources that are treated as Existing Generating Capacity Resources in the fourth Forward Capacity Auction pursuant to Section III.13 of the Tariff shall receive treatment as a NR and obtain NR Interconnection Services in accordance with this SGIP, up to the NR Capability of the resource. The grandfathered NR Capability shall be determined pursuant to the hierarchy set forth in Section 1.6.4.3.

Where the governing document (as described by the hierarchy set forth in Section 1.6.4.3) of a resource for which a temperature-adjustment curve is used for the claimed capability verification, as set forth in the ISO New England Manuals, specifies a megawatt amount at an ambient temperature, the grandfathered NR Capability shall be equal to a temperature-adjusted value consistent with the definition of NR Capability.

Where the governing document (as determined by the hierarchy set forth in Section 1.6.4.3) does not specify an ambient temperature, the megawatt amount will be deemed to be at the value consistent with the definition of NR Capability.

1.7 Type of Interconnection Services

At the time the Interconnection Request is submitted, the Interconnection Customer must request either CNR Interconnection Service or NR Interconnection Service, as described in Sections 1.7.1 and 1.7.2 below. An Interconnection Customer that meets the requirements to obtain CNR Interconnection Service shall obtain NR Interconnection Service up to the NR Capability upon completion of all requirements for NR Interconnection Service, including all necessary upgrades. Upon completion of all requirements for the CNR Interconnection Service, the Interconnection Customer shall also receive CNR Interconnection Service for CNR Capability. An Interconnection Customer that meets the requirements to obtain NR Interconnection Service shall receive NR Interconnection Service for the Interconnection Customer's Generating Facility NR Capability.

1.7.1 Capacity Network Resource Interconnection Service

1.7.1.1 **The Product.** The System Operator must conduct the necessary studies in conjunction with the Interconnecting Transmission Owner, and with other Affected Parties as appropriate and in accordance with applicable codes of conduct and confidentiality requirements, and the Interconnecting Transmission Owner and other Affected Parties as appropriate must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which CNRs are interconnected under the CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Small Generating Facility to be designated as a CNR, and to participate in the New England Markets, in accordance with the Tariff, up to the CNR Capability or as otherwise provided in the Tariff, on the same basis as existing CNRs, and to be studied as a CNR on the assumption that such a designation will occur.

1.7.1.2 **The Studies.** All Interconnection Studies for CNR Interconnection Service shall assure that the Interconnection Customer's Small Generating Facility satisfies the minimum characteristics required to interconnect in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System. The CNR Group Study for CNR Interconnection Service shall assure that the Interconnection Customer's Small Generating Facility can be interconnected in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other CNRs and Elective Transmission Upgrades with CNI Interconnection Service, in accordance with the CC Interconnection Standard and as detailed in the ISO New England Planning Procedures. The Interconnection Request may also be studied with the New England Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the System Operator and as appropriate the Interconnecting Transmission Owner must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

1.7.1.3 **Milestones for CNR Interconnection Service.** In addition to the requirements set forth in this SGIP, an Interconnection Customer with an Interconnection Request for CNR Interconnection Service shall complete the following milestones prior to receiving CNR Interconnection Service for the CNR Capability, such milestones to be specified in Attachment 4 of the SGIA as either completed or to be completed: (i) submit the necessary requests for participation in the Forward Capacity Auction associated with the Generating Facility's requested Commercial Operation Date (except as modified by Agreement with the System Operator pursuant to Section 1.5.5 of this SGIP), in accordance with the provisions of

Section III.13 of the Tariff; (ii) participate in a CNR Group Study for the Forward Capacity Auction associated with the requested Generating Facility's Commercial Operation Date; (iii) qualify and receive a Capacity Supply Obligation in accordance with Section III.13 of the Tariff; and (iv) complete a re-study of the applicable Interconnection Study and CNR Group Study after the Forward Capacity Auction, Reconfiguration Auction, or bilateral transaction through which the Interconnection Customer received a Capacity Supply Obligation to determine the cost responsibility for facilities and upgrades necessary to accommodate the Interconnection Request. The re-study shall include those CNR Interconnection Service or CNI Interconnection Service Interconnection Requests with a higher Queue Position that cleared and shall exclude any upgrades that are no longer necessary as a result of existing capacity that will be retired as of the start of the Capacity Commitment Period for which the resource has received a Capacity Supply Obligation. With respect to (iv) above, if an Interconnection Study Agreement has been executed, the Interconnection Study associated with the Interconnection Study Agreement shall include the necessary analysis that would otherwise have been performed in a re-study. If the original Interconnection Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Study Agreement. If an SGIA has been either executed or filed with the Commission in unexecuted form, then the last Interconnection Study completed for the Interconnection Customer under this SGIP shall be subject to re-study. The Attachments to the SGIA shall be amended (pursuant to Article 12.2 of the SGIA) to reflect CNR Capability and the results of the re-study.

1.7.2 Network Resource Interconnection Service

1.7.2.1 The Product. The System Operator must conduct the necessary studies in conjunction with the Interconnecting Transmission Owner, and with other Affected Parties as appropriate and in accordance with applicable codes of conduct and confidentiality requirements, and the Interconnecting Transmission Owner and other Affected Parties as appropriate must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which Network Resources are interconnected under the NC Interconnection Standard. NR Interconnection Service allows the Interconnection Customer's Small Generating Facility to participate in the New England Markets in accordance with the provisions of Market Rule 1, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as other Network Resources. Notwithstanding the above, the portion of a Small Generating Facility that has been designated solely as a Network Resource interconnected under the NC Interconnection Standard cannot

be a capacity resource under Section III.13 of the Tariff, except pursuant to a new Interconnection Request for CNR Interconnection Service.

1.7.2.2 The Studies. The Interconnection Studies for an Network Resource shall assure that the Interconnection Customer's Small Generating Facility satisfies the minimum characteristics required to interconnect in a manner that avoids any significant adverse effect on reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the unit, in accordance with the NR Interconnection Standard and as detailed in the ISO New England Planning Procedures. The System Operator, in coordination with the Interconnecting Transmission Owner, may also study the New England Transmission System under non-peak load conditions.

However, upon request by the Interconnection Customer, the System Operator and as appropriate the Interconnecting Transmission Owner must explain in writing to the Interconnecting Transmission Owner why the study of non-peak load conditions is required for reliability purposes.

1.7.2.3 Milestones for NR Interconnection Service. An Interconnection Customer with an Interconnection Request for NR Interconnection Service shall complete the requirements in this SGIP prior to receiving NR Interconnection Service.

1.8 Withdrawal

1.8.1 The Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to System Operator, which System Operator will transmit to the Interconnecting Transmission Owner and any Affected Parties. In addition, if the Interconnection Customer fails to adhere to all requirements of this SGIP, except as provided in Section 4.2 (Disputes), the System Operator shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Except as otherwise provided elsewhere in this SGIP, upon receipt of such written notice, the Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cure the deficiency or to notify the System Operator of its intent to pursue dispute resolution, and the System Operator shall notify the Interconnecting Transmission Owner and any Affected Parties of the same.

1.8.2 Withdrawal shall result in the loss of the Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during dispute resolution, the System Operator may eliminate the Interconnection Customer's Interconnection Request from the queue until such time that the outcome of dispute resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to System Operator, Interconnecting Transmission Owner, and any Affected Parties all costs prudently incurred with respect to that Interconnection Request prior to the System Operator's receipt of notice described above. The Interconnection Customer must pay all monies due before it is allowed to obtain any interconnection study data or results.

1.8.3 The System Operator shall update the OASIS Queue Position posting. The System Operator and Interconnecting Transmission Owner shall: (i) arrange to refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceeds the costs incurred; or (ii) arrange to charge to the Interconnection Customer any amount of such costs incurred that exceed the Interconnection Customer's deposit or study payments. In the event of such withdrawal, the System Operator, subject to the confidentiality provisions of Section 4.5 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information, shall provide, at Interconnection Customer's request, all information developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

SECTION 2. FAST TRACK PROCESS

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Distribution System that is part of the Administered Transmission System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than or equal to 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the System Operator in conjunction with the Interconnecting Transmission Owner has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline ¹ and ≤ 2.5 Electrical Circuit Miles from Substation ²
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and < 69 kV	≤ 4 MW	≤ 5 MW

1. For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

2. An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

2.2 Initial Review

Within fifteen (15) Business Days after the System Operator notifies the Interconnection Customer it has received a complete Interconnection Request, the System Operator in conjunction with the Interconnecting Transmission Owner shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Interconnecting Transmission Owner's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of an Interconnecting Transmission Owner's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Interconnecting Transmission Owner's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Interconnecting Transmission Owner on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved for Network Resource interconnection Service and the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer an executable SGIA within five (5) Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the System Operator in conjunction with the Interconnecting Transmission Owner determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the System Operator in

conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer an executable SGIA within five (5) Business Days after the determination. If the Interconnection Request is for Capacity Network Resource Interconnection Service, the Interconnection Customer must also comply with the milestones for CNR Interconnection Service specified in Section 1.7.1.3 of the SGIP.

2.2.4 If the proposed interconnection fails the screens, but the System Operator in conjunction with the Interconnecting Transmission Owner, does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the System Operator in conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the System Operator in conjunction with the Interconnecting Transmission Owner determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the System Operator shall notify the Interconnection Customer of that determination within five (5) Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten (10) Business Days of such determination, the System Operator shall offer to convene a customer options meeting with the Interconnection Customer and Interconnecting Transmission Owner to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the determination, or at the customer options meeting:

2.3.1 The Interconnecting Transmission Owner shall offer to perform facility modifications or minor modifications to the Interconnecting Transmission Owner's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Interconnecting Transmission Owner's electric system. If the Interconnection Customer agrees to pay for the modifications to the Interconnecting Transmission Owner's electric system, the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer with an executable SGIA within ten (10) Business Days of the customer options meeting; or

2.3.2 The System Operator shall offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 The System Operator shall obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit to the System Operator for the estimated costs of the supplemental review in the amount of the System Operator's and Interconnecting Transmission Owner's good faith estimate of the costs of such review, both within fifteen (15) Business Days of the offer. If the written agreement and deposit have not been received by the System Operator within that timeframe, the Interconnection Request shall continue to be evaluated under the section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer must specify the order in which the System Operator in conjunction with the Interconnecting Transmission Owner will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the System Operator's and the Interconnecting Transmission Owner's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the System Operator and Interconnecting Transmission Owner will return such excess within twenty (20) Business Days of the invoice without interest.

2.4.4 Within thirty (30) Business Days following receipt of the deposit for a supplemental review, the System Operator shall (1) in conjunction with the Interconnecting Transmission Owner, perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the System Operator's and Interconnecting Transmission Owner's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of

supplemental review, the System Operator shall notify the Interconnection Customer following the failure of any of the screens, or if the System Operator in conjunction with the Interconnecting Transmission Owner is unable to perform the screen in section 2.4.4.1, within two (2) Business Days of making such determination to request Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 Minimum Load Screen: Where twelve (12) months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the System Operator in conjunction with the Interconnecting Transmission Owner shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4.4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Interconnecting Transmission Owner's electric system will be considered as part of the aggregate generation.

2.4.4.1.3 The System Operator and the Interconnecting Transmission Owner will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The System Operator in conjunction with the Interconnecting Transmission Owner shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section is uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer with an executable SGIA within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Interconnecting Transmission Owner on its own system, the SGIA shall be provided within ten (10) Business Days after the notification of the supplemental review results.

2.4.5.2 If Interconnection Facilities or minor modifications to the Interconnecting Transmission Owner's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Interconnecting Transmission Owner's electric system, the SGIA, along with a non-binding good faith estimate for the Interconnection Facilities and/or minor modifications, shall be provided to the Interconnection Customer within fifteen (15) Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than Interconnection Facilities or minor modifications to the Interconnecting Transmission Owner's system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the System Operator shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

SECTION 3. STUDY PROCESS

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Administered Transmission System if the Small Generating Facility is no

larger than 20 MW and does not meet the eligibility requirements of section 2.1 or does not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The System Operator, the Interconnecting Transmission Owner, the Interconnection Customer and the Affected Party(ies) will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. Before participating in a scoping meeting with an Interconnection Customer that is also an Affiliate, the Interconnecting Transmission Owner shall post on the OASIS an advance notice of its intent to do so.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request, including: (i) the estimated timeline for completing all applicable Interconnection Studies, (ii) exchange pertinent information including any transmission data that would reasonably be expected to impact interconnection options, (iii) analyze such information, and (iv) determine the potential feasible Points of Interconnection, and (v) to discuss any other information necessary to facilitate the administration of the Interconnection Procedures. A PSCAD model is required for all wind and inverter-based Small Generating Facilities. If a PSCAD model is required for other Small Generating Facility types, the Parties shall discuss this at the Scoping Meeting. The Parties shall discuss whether the System Operator should perform an Interconnection Feasibility Study or proceed directly to an Interconnection System Impact Study, or an Interconnection Facilities Study, or an SGIA. If the Interconnection Customer provides the technical data called for in Attachment 2 (including Attachment A, if applicable) to this SGIP with the Interconnection Request, the Parties shall discuss the detailed project design at the Scoping Meeting.

Unless the Interconnection Request has been identified to be included in a CRPS or eligible for inclusion in a CSIS, within five (5) Business Days following the scoping meeting, the Interconnection Customer shall notify the System Operator, in writing: (i) whether it wants the Interconnection Feasibility Study to be completed, as a separate and distinct study or as part of the Interconnection System Impact Study, (ii) if requesting the Interconnection Feasibility Study be completed as a separate and distinct study, which of the alternative study scopes is being selected pursuant to Section 3.3.2, and (iii) the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection for inclusion in the attachment

to the Interconnection Feasibility Study Agreement (Attachment 6), or the Interconnection System Impact Study Agreement (Attachment 7) if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested an Interconnection Feasibility Study must return the executed Interconnection Feasibility Study Agreement (or Interconnection System Impact Study Agreement if the Interconnection Customer elected not to pursue the Interconnection Feasibility Study), within fifteen (15) Business Days.

3.3 Interconnection Feasibility Study

3.3.1 Interconnection Feasibility Study Agreement. Within five (5) Business Days following the Interconnection Customer's request for an Interconnection Feasibility Study, the System Operator shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by the System Operator and Interconnecting Transmission Owner, including an outline of the scope of the Interconnection Feasibility Study and a non-binding good faith estimate of the cost to perform the Interconnection Feasibility Study. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). No later than fifteen (15) Business Days after its receipt of the Interconnection Feasibility Study Agreement, the Interconnection Customer shall execute and deliver the agreement, including completed attachments, to System Operator and the Interconnecting Transmission Owner, together with the refundable deposit of the lesser of 50 percent of the good faith estimated Interconnection Feasibility Study costs or earnest money of \$1,000. The deposit shall be applied toward the cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS. Any difference between the study deposit and the actual cost of the Interconnection Feasibility Study or the actual costs incurred by the Interconnecting Transmission Owner in developing the costs estimates in support of the CRPS shall be paid by or refunded to the Interconnection Customer. The System Operator and/or Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of the Interconnection Feasibility Study that have

been incurred by the System Operator and/or the Interconnecting Transmission Owner on the Interconnection Feasibility Study, including the development of the study agreement and its attachment(s). The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Feasibility Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. System Operator shall continue to hold any amounts on deposits until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.3.2 Scope of Interconnection Feasibility Study. The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Administered Transmission System with available data and information. The Interconnection Feasibility Study will consider the Base Cases as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission (the “Study Case” for the Interconnection Feasibility Study). An Interconnection Customer with a CNR Interconnection Request may also request that the Interconnection Feasibility Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer’s Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection Feasibility Study Agreement. The Interconnection Feasibility Study will consist of a power flow, including thermal analysis and voltage analysis, and short circuit analysis. The Interconnection Feasibility Study report will provide (i) a list of facilities and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct the Interconnection Facilities and Network Upgrades; (iii) a protection assessment to determine the required Interconnection Facilities; and may provide (iv) an evaluation of the siting of Interconnection Facilities and Network Upgrades; and (v) identification of the

likely permitting and siting process including easements and environmental work for Interconnection Facilities and Network Upgrades.

Alternatively, in the case where the Interconnection Customer requests that the Interconnection Feasibility Study be completed as a separate and distinct study, the Interconnection Customer may provide the technical data called for in Appendix 1, Attachment A with the executed Interconnection Feasibility Study Agreement and request that the Interconnection Feasibility Study consist of limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting. In this case, the Interconnection Feasibility Study report will provide (i) the study findings; and, (ii) a preliminary description of and a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study.

To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.3, the Interconnection Feasibility Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.3.3 Interconnection Feasibility Study Procedures. The System Operator in coordination with Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than thirty (30) Business Days after System Operator and Interconnecting Transmission Owner receive the fully executed Interconnection Feasibility Study Agreement, study deposit and required technical data in accordance with Section 3.3.1. At the request of the Interconnection Customer or at any time the System Operator or the Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the System Operator is unable to complete the Interconnection Feasibility Study within that time period, the System Operator shall notify the

Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

3.3.4 Meeting with Parties. Within ten (10) Business Days of providing an Interconnection Feasibility Study report to the Interconnection Customer, the System Operator will convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements to discuss the results of the Interconnection Feasibility Study.

3.3.5 Re-Study. If re-study of the Interconnection Feasibility Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resources(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Feasibility Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Feasibility Study Agreement. The Interconnection Customer shall have the option to waive the re-study and elect to have the re-study performed as part of its Interconnection System Impact Study. The Interconnection Customer shall provide written notice of the waiver and election of moving directly to the Interconnection System Impact Study within five (5) Business Days of receiving notice from the System Operator of the required re-study.

3.4 Interconnection System Impact Study

3.4.1 Interconnection System Impact Study Agreement. Within five (5) Business Days following the Interconnection Feasibility Study results meeting, the System Operator and Interconnecting Transmission Owner shall provide to Interconnection Customer the Interconnection System Impact Study Agreement, which includes a non-binding good faith estimate of the cost and timeframe to perform the

Interconnection System Impact Study. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA.

3.4.2 Execution of Interconnection System Impact Study Agreement. The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement, including completed attachments, to the System Operator no later than fifteen (15) Business Days after its receipt along with (1) demonstration of Site Control, (2) a refundable deposit of 50 percent of the good faith estimated cost for the transmission portion of the Interconnection System Impact Study and 100 percent of the good faith estimated cost for the distribution portion of the Interconnection System Impact Study, and (3) a PSCAD model if one was determined to be needed at the Scoping Meeting; provided that if a PSCAD model was determined to be needed for the non-wind or non-inverter-based Small Generating Facility at the Scoping Meeting, then the Interconnection Customer shall have ninety (90) Calendar Days from the execution of the System Impact Study Agreement to provide the PSCAD model. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. The deposit shall be applied toward the cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA. For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS. Any difference between the study deposit and the actual cost of the Interconnection System Impact Study or the actual costs incurred by the Interconnecting Transmission Owner in developing the costs estimates in support of the CRPS shall be paid by or refunded to the Interconnection Customer. The System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of Interconnection System Impact Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the System Impact Study, including the study agreement and its attachment(s) and the SGIA. In the case of Clustering, CSIS costs that are associated with an individual Interconnection Request assessed within the CSIS will be

charged directly to that Interconnection Customer. CSIS costs that are associated with the CSIS as a whole will be divided equally, on a per-project basis, among the Interconnection Customers in the cluster.

The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the transmission portion of the Interconnection System Impact Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold the amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.4.3 Scope of Interconnection System Impact Study. The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability and operation of the New England Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission (the “Study Case” for the Interconnection System Impact Study). An Interconnection Customer with a CNR Interconnection Request that elected to waive the Interconnection Feasibility Study may also request that the Interconnection System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer’s Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection System Impact Study Agreement. The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis and any other analyses, such as electromagnetic transient analysis, that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner. The Interconnection System Impact Study report will state the assumptions upon

which it is based, state the results of the analyses, and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study report will provide (i) a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility, (ii) a non-binding good faith estimated time to construct, (iii) a protection assessment to determine the required protection upgrades; and may provide (iv) an evaluation of the siting of the Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.4.3, the Interconnection System Impact Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.4.4 Interconnection System Impact Study Procedures. The System Operator shall coordinate the Interconnection System Impact Study with the Interconnecting Transmission Owner, and with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, that is affected by the Interconnection Request. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection System Impact Study within forty-five (45) Business Days after the receipt of the Interconnection System Impact Study Agreement, study deposit, demonstration of Site Control, if Site Control is required, and required technical data in accordance with Section 3.4.2. If the System Operator uses Clustering, the System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within the times specified in this Section 3.4.4. At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the System Operator and Interconnecting Transmission Owner are unable to complete the Interconnection System Impact Study within the time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Except in the case of a CSIS, the System Operator shall notify the Interconnection Customer when the Interconnection System Impact Study is expected to commence within sixty-five (65) Calendar Days. An Interconnection Customer with an Interconnection Request being studied serially will be permitted to update the technical data provided in Attachment 2 of this SGIP and any attachments thereto, and submit modifications to that technical data to the System Operator no later than sixty (60) Calendar Days from the date that the System Operator notified the Interconnection Customer that the Interconnection System Impact Study is expected to commence. Such modifications will not be deemed Material Modifications unless the changes require a new Interconnection Request in accordance with Section 1.5.5 of this SGIP.

Where sufficient time has elapsed since the initial Scoping Meeting, within ten (10) Business Days after notifying the Interconnection Customer that the Interconnection System Impact Study is expected to commence, the System Operator may convene a second Scoping Meeting for the purpose of providing updated information to the Interconnection Customer in preparation for the submittal of updates to the technical data.

3.4.5 Meeting with Parties. Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, the System Operator shall convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, to discuss the results of the Interconnection System Impact Study. Within ten (10) Business Days following the study results meeting, the Interconnection Customer shall provide to the System Operator written notice that it will either pursue the Interconnection Facilities Study or waive the Interconnection Facilities Study and elect an expedited interconnection. Once the Interconnection Customer notifies the System Operator of its election, such election is not subject to change. If the Interconnection Customer elects to pursue the Facilities Study it must proceed with the study. If the Interconnection Customer waives the Facilities Study, it shall commit to the following milestones in the SGIA: (i) Siting approval for the Generating Facility and Interconnection Facilities; (ii) Engineering of Interconnection Facilities approved by Interconnecting Transmission Owner; (iii) Ordering of long lead time material for Interconnection Facilities and system upgrades; (iv) Initial Synchronization Date; and (v) Commercial Operation Date.

Within thirty (30) Calendar Days of the Interconnection Customer receiving the Interconnection System Impact Study report, the Interconnection Customer shall provide written comments on the report or written notice that it has no comments on the report. The System Operator shall issue a final Interconnection System Impact Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's notice that it will not provide comments.

3.4.6 Re-Study. If re-study of the Interconnection System Impact Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resources(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection System Impact Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection System Impact Study Agreement.

3.4.7 Operational Readiness. The System Operator shall, as close to the Interconnection Customer's actual Synchronization Date as reasonably possible, ensure that operational analysis, including current stability analyses, power flow analyses, and any other analyses deemed necessary by the System Operator, are performed, and that procedures are developed or updated to address the operation of the New England Transmission System with the addition of the Interconnection Customer's Generating Facility. The operational analysis will also include tests of system performance with selected facilities out of service. Such studies shall be performed at the expense of the Interconnection Customer. The System Operator is not obligated to perform the operational analyses described in this Section 3.4.7 if, in the exercise of reasonable discretion, the System Operator in consultation with Interconnecting Transmission Owner determines that interconnection of the Interconnection Customer's Generating Facility to the Administered Transmission System is remote and speculative.

3.5 Interconnection Facilities Study

3.5.1 Interconnection Facilities Study Agreement. Except as otherwise provided in Section 1.5.3.4 of this SGIP, the Interconnection Customer may waive the Interconnection Facilities Study and instead elect expedited interconnection and proceed with a SGIA in accordance with the requirements specified in Section 4.8. If the Interconnection Customer elects to proceed with an Interconnection Facilities Study, the System Operator shall provide to the Interconnection Customer an Interconnection Facilities Study Agreement in the form of Attachment 8 to this SGIP simultaneously with the delivery of the Interconnection System Impact Study report to the Interconnection Customer. The Interconnection Facilities Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection Facilities Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA. Within five (5) Business Days following the Interconnection Customer's Interconnection System Impact Study results meeting, the System Operator and Interconnecting Transmission Owner shall provide to the Interconnection Customer the Interconnection Facilities Study Agreement along with a non-binding good faith estimate of the cost to perform the Interconnection Facilities Study. The Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement, including completed attachments, to the System Operator within thirty (30) Business Days after its receipt, together with the required refundable deposit of the non-binding good faith estimated costs for the Interconnection Facilities Study. Any difference between the study deposit and the actual cost of the Interconnection Facilities Study shall be paid by or refunded to the Interconnection Customer. The System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the cost of the Interconnection Facilities Studies that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the Interconnection Facilities Study, the study agreement and its attachment(s) and the SGIA. In the case of Clustering, CFAC costs that are associated with an individual Interconnection Request assessed within the CFAC will be charged directly to that Interconnection Customer. CFAC costs that are associated with the CFAC as a whole will be divided equally, on a per-project basis, among the Interconnection Customers in the cluster. The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of

invoice. The System Operator shall continue to hold the amounts on deposits until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.5.2 Scope of Interconnection Facilities Study. The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Administered Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Interconnecting Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The scope and cost of the Interconnection Facilities Study shall include completion of any engineering work limited to what is reasonably required to (i) estimate such aforementioned cost, (ii) identify configurations of required facilities, and (iii) identify time requirements for construction and installation of required facilities. Design for any required Interconnection Facilities and/or Network Upgrades shall also be performed under the Interconnection Facilities Study. The Interconnection Customer, the System Operator, the Interconnecting Transmission Owner, and the Affected Party(ies), if any, may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design shall be reviewed and may be modified prior to acceptance by the Interconnecting Transmission Owner, under the provisions of the Interconnection Facilities Study Agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the System Operator and/or the Interconnecting Transmission Owner shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain any independent design and cost estimates for any necessary facilities.

3.5.3 Interconnection Facilities Study Procedures. The System Operator shall coordinate the Interconnection Facilities Study with Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. The System

Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the study and the System Operator shall issue a draft Interconnection Facilities Study report to the Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: forty-five (45) Business Days if upgrades are necessary, or thirty (30) Business Days if upgrades are not necessary. If the System Operator uses Clustering, the System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to deliver a completed Interconnection Facilities Study within the times specified in this Section 3.5.3.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Facilities Study, System Operator shall notify the Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, as to the schedule status of the Interconnection Facilities Study. If the System Operator is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, the System Operator shall notify the Interconnection Customer, Interconnecting Transmission Owner and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and provide an estimated completion date and an explanation of the reasons why additional time is required. The Interconnection Customer and appropriate Affected Parties may, within thirty (30) Business Days after receipt of the draft report, provide written comments to the System Operator and Interconnecting Transmission Owner, which the System Operator shall include in the final report. The System Operator shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The System Operator may reasonably extend such fifteen-day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the System Operator or Interconnecting Transmission Owner to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities report. Upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, or any third party consultant retained by the Interconnection Customer or to any non-market affiliate of the

Interconnection Customer supporting documentation, with workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study. The recipient(s) of such information shall be subject to the confidentiality provisions of this SGIP and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/ disclosure requirements, such information may be provided directly to the Interconnection Customer.

3.5.4 Meeting with Parties. Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, the System Operator will convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements to discuss the results of the Interconnection Facilities Study. Within thirty (30) Business Days of receipt of the study results, the Interconnection Customer shall provide written notice whether it agrees to pay for the Interconnection Facilities and upgrades identified in the Interconnection Facilities Study. An executable SGIA shall be tendered by the System Operator in conjunction with the Interconnecting Transmission Owner to the Interconnection Customer within five (5) Business Days of receipt of such agreement.

3.5.5 Re-Study. If re-study of the Interconnection Facilities Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resource(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall so notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Facilities Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Facilities Study Agreement.

SECTION 4. PROVISIONS THAT APPLY TO ALL INTERCONNECTION REQUESTS

4.1 Reasonable Efforts

The System Operator and Interconnecting Transmission Owner shall make Reasonable Efforts to meet all time frames provided in these procedures unless the System Operator, the Interconnecting Transmission Owner and the Interconnection Customer agree to a different schedule. If the System Operator or Interconnecting Transmission Owner cannot meet a deadline provided herein, it shall notify the other Parties, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, the Party initiating the dispute resolution process shall provide the other Party(ies) with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two (2) Business Days after receipt of the Notice, any Party may contact the Commission's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for its own costs and its pro rata share of any costs paid to the neutral party and any associated common negotiating costs.

4.2.6 If none of the Parties elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then each Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Commission, state, or local regulatory requirements and with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards.

4.4.1 The System Operator and the Interconnecting Transmission Owner must be given at least five (5) Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5 Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party(ies) that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such. Confidential information shall include, without limitation, all information treated as confidential under the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the others prior to the execution of an SGIA.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party(ies) and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party(ies) as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if the Commission, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) prior to the release of the Confidential Information to the Commission. The Party shall notify the other Party(ies) when it is notified by the Commission that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The System Operator shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The System Operator and Interconnecting Transmission Owner shall use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Interconnecting Transmission Owner, its subsidiaries or affiliates, or others.

4.7 Record Retention

The System Operator shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 SGIA

In accordance with Section 3, the System Operator and the Interconnecting Transmission Owner shall tender to the Interconnection Customer a draft SGIA, together with draft attachments completed to the extent practicable. The Interconnection Customer shall return the Interconnection Customer specific information required to complete the form SGIA, including the attachments, within fifteen (15) Business Days. Within five (5) Business Days, the System Operator and the Interconnecting Transmission Owner shall issue a final draft of the SGIA to the Interconnection Customer.

The Interconnection Customer and the Interconnecting Transmission Owner shall have fifteen (15) Business Days or another mutually agreeable timeframe to sign three (3) originals of the SGIA and return them to the System Operator, who will send an original fully executed SGIA to Interconnecting Transmission Owner and Interconnection Customer, or the Interconnection Customer shall request that an unexecuted SGIA be filed with the Commission. If the Interconnection Customer does not sign the SGIA, or ask that it be filed unexecuted within thirty (30) Business Days after its receipt of the final draft of the SGIA, the Interconnection Request shall be deemed withdrawn. After the SGIA is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the SGIA.

The Interconnection Customer, the Interconnecting Transmission Owner and the System Operator shall be Parties to the SGIA.

Within fifteen (15) Business Days after receipt of the final SGIA, an Interconnection Customer with an Interconnection Request studied using Clustering that provided the additional Cluster Participation Deposit in accordance with Section 1.5.3.4.4 shall provide to the Interconnecting Transmission Owner, in cash, a potentially non-refundable deposit of twenty (20) percent of the total costs for the Interconnection Facilities and other upgrades, including any CETUs, identified in the CFAC, unless the Interconnecting Transmission Owner's expenditure schedule for the Interconnection Facilities and other upgrades calls for an initial payment of greater than twenty (20) percent of the total upgrade costs, in which case the scheduled initial payment must instead be made within the fifteenth Business Day after receipt of the final SGIA. If the Interconnection Customer does not submit this deposit (or make the initial payment) by the fifteenth Business Day after receipt of the final SGIA, the Interconnection Request shall be automatically withdrawn from the interconnection queue without further opportunity to cure, and the Interconnection Customer's initial and additional Cluster Participation Deposits shall become non-refundable. The non-

refundable initial and additional Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in the cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation. If an Interconnection Request is withdrawn after the Interconnection Customer's payment of twenty (20) percent of the total cost responsibility for the upgrades to the Interconnecting Transmission Owner, then the payment shall be used to offset the costs of the CETU. Any unspent payments of the total cost responsibility for the upgrades to the Interconnecting Transmission Owner will be refunded to the respective Interconnection Customers that executed the Interconnection Agreement and provided to the Interconnecting Transmission Owner the twenty (20) percent deposit (or initial payment) if all the associated Interconnection Requests are withdrawn from the interconnection queue and the associated Interconnection Agreements are terminated.

4.9 Coordination with Affected Systems

The System Operator shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The System Operator will include such Affected System operators in all meetings held with the Interconnection Customer as required by the SGIP. The Interconnection Customer will cooperate with the System Operator and the Interconnecting Transmission Owner in all matters related to the conduct of studies and the determination of modifications to Affected Systems. The Interconnection Customer shall be responsible for the costs associated with the studies or portions of studies associated with the Affected Systems. Payment and refunds associated with the costs of such studies will be coordinated between the Interconnection Customer and the Affected Party(ies). The System Operator shall seek the cooperation of all Affected Parties in all matters related to the conduct of studies and the determination of modifications to Affected Systems. Nothing in the foregoing is intended to authorize the Interconnection Customer to receive interconnection, related facilities or other services on an Affected System, and provision of such services must be handled through separate arrangements with Affected Parties.

4.10 Evaluation of a Small Generating Facility Interconnection Request

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total energy capability or capacity capability of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System. However, if the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the System Operator's and Interconnecting Transmission Owner's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Administered Transmission System. If the System Operator and the Interconnecting Transmission Owner do not agree with the manner in which the Interconnection Customer proposes to implement the limit, then the Interconnection Request must be withdrawn or revised to specify the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System without such limitations. Furthermore, nothing in this section shall prevent the System Operator from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard (“CC Interconnection Standard”) – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource (“CNR”) – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability (“CNR Capability”) – The MW quantity associated with CNR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Capacity Network Resource Group Study (“CNR Group Study”) – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service (“CNR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer’s CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Cluster Enabling Transmission Upgrade (“CETU”) shall mean new significant transmission line infrastructure that consists of AC transmission lines and related terminal equipment having a nominal voltage rating at or above 115 kV or HVDC transmission lines and HVDC terminal equipment that is identified through the Clustering Enabling Transmission Upgrade Regional Planning Study conducted to accommodate the Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered. The CETU shall be considered part of a Generator Interconnection Related Upgrade and be categorized as Interconnection Facilities or Network Upgrades.

Cluster Enabling Transmission Upgrade Regional Planning Study (“CRPS”) shall mean a study conducted by the System Operator under Attachment K, Section II of the Tariff to identify the Cluster Enabling Transmission Upgrade and associated system upgrades to enable the interconnection of Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered.

Cluster Interconnection Facilities Study (“CFAC”) shall mean an Interconnection Facilities Study performed using Clustering pursuant to Section 1.5.3.4.

Cluster Interconnection System Impact Study (“CSIS”) shall mean an Interconnection System Impact Study performed using Clustering pursuant to Section 1.5.3.3.

Cluster Participation Deposit shall mean the initial and additional deposit due under Sections 1.5.3.3.2.2 and 1.5.3.4.4.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – For a unit, the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Standard Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner’s facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner’s Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Generating Facility – The Interconnection Customer’s device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities.

Initial Synchronization Date – The date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date – The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner’s Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner – A Transmission Owner that owns, leases or otherwise possesses an interest, or a Non-Incumbent Transmission Developer that is not a Participating Transmission Owner that is constructing, a portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Small Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner’s Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Attachment 2 to the Standard Small Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner’s Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer – Any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Small Generating Facility with the Administered Transmission System under the Standard Small Generator Interconnection Procedures.

Interconnection Customer’s Interconnection Facilities shall mean all facilities and equipment, as identified in Attachment 2 of the Standard Small Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer’s Interconnection Facilities are sole use facilities.

Interconnection Facilities – The Interconnecting Transmission Owner’s Interconnection Facilities and the Interconnection Customer’s Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study – A study conducted by the System Operator, Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner’s Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 3.5.2 of the Standard Small Generator Interconnection Procedures.

Interconnection Facilities Study Agreement – The form of agreement contained in Attachment 8 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study – A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 3.3 of the Standard Small Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection Feasibility Study Agreement – The form of agreement contained in Attachment 6 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request – The Interconnection Request shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP; (iv) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (v) commence participation in the wholesale markets by, an existing Generating Facility that is interconnected with the Administered Transmission System; or (vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service – The service provided by the System Operator and the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Small Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study – Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard

Small Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement – Any of the following agreements: The Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement attached to the Standard Small Generator Interconnection Procedures.

Interconnection System Impact Study – An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Small Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection System Impact Study Agreement – The form of agreement contained in Attachment 7 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Network Capability Interconnection Standard (“NC Interconnection Standard”) – The minimum criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Network Resource (“NR”) – The portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.

Network Resource Capability (“NR Capability”) – The MW quantity associated with NR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Network Resource Interconnection Service (“NR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Generating Facility to the Administered Transmission System in accordance with the Network Capability Interconnection Standard. An Interconnection Customer’s NR Interconnection Service shall be solely for the megawatt amount of the NR Capability. NR Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the New England Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Administered Transmission System to accommodate the interconnection with the Small Generating Facility to the Administered Transmission System. Network Upgrades do not include Distribution Upgrades.

Notice of Dispute – A written notice of a dispute or claim that arises out of or in connection with the Standard Small Generator Interconnection Agreement or its performance.

Party– The System Operator, Interconnecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Administered Transmission System.

Queue Position – The order of a valid request in the New England Control Area, relative to all other pending valid requests in the New England Control Area, that is established based upon the date and time of receipt of the valid Interconnection Request by the System Operator. Requests are comprised of interconnection requests for Generating Facilities, Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified

by the other electric systems, that impact the Administered Transmission System. References to a “higher-queued” Interconnection Request shall mean one that has been received by System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as “lower-queued.”

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the SGIP or SGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – A Generating Facility having a maximum gross capability at or above zero degrees F of 20 MW or less.

Stand Alone Network Upgrades – Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Attachment 2 to the Standard Small Generator Interconnection Agreement.

Study Case shall have the meaning specified in Sections 3.3.2 and 3.4.3 of this SGIP.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study.

Tariff - The System Operator’s or Affected System’s Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation – The period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Upgrades – The required additions and modifications to the Administered Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

**SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)**

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP Section 1.4, documentation of Site Control must be submitted with the Interconnection Request, except where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the proposed modifications do not require additional real property.

_____ Site Control is not provided because the proposed modification is to the Interconnection Customer's existing Small Generating Facility and, by checking this option, the Interconnection Customer certifies that it has Site Control and that the proposed modification does not require additional real property.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection that is subject to this SGIP must submit this Interconnection Request to the System Operator via the Interconnection Request Tracking Tool or IRTT, a web-based application for submitting, tracking and viewing Interconnection Requests available on the ISO New England website.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is \$4.50/kW (minimum of \$300 and maximum of \$7,500). The kW are the maximum gross kW of the Small Generating Facility. The Fast Track Process is limited to a Small Generating Facility that meets the eligibility requirements of section 2.1 and certain codes, standards and certification requirements.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the System Operator a non-refundable deposit of \$2,500 towards the cost of the scoping

meeting, the development of the interconnection study agreements, interconnection studies, and development of the SGIA. For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the non-refundable deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS.

Interconnection Customer Information

Proposed Project Name: _____

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: _____

ISO Customer ID# (if available): _____

Contact Person: _____

Mailing Address: _____

City: _____ County: _____ State: _____ Zip: _____

Facility Location (if different from above): _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

- Application is for: _____ New Small Generating Facility
_____ Capacity addition to or modification of an existing Small Generating Facility
_____ Commencement of participation in the wholesale markets by an existing Small Generating Facility
_____ A change from Network Resource Interconnection Service to Capacity Network Resource Interconnection Service

If capacity addition to or modification of an existing facility, please describe: _____

If the capacity addition increases the maximum gross megawatt electrical output at an ambient temperature of 20 degrees F of the Generating Facility to more than 20 MW, the Interconnection Customer shall apply under Schedule 22.

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___ No ___

To Supply Power to Others? Yes ___ No ___

Is the Interconnection Request for:

Service Type (check one):

_____Capacity Network Resource Interconnection Service (energy capability and capacity capability) or

_____Network Resource Interconnection Service (energy capability only)

A retail customer interconnecting a new Small Generating Facility that will produce electric energy to be consumed only on the retail customer's site? Yes____No____

A Qualifying Facility where 100% of the output will be sold to its host utility?
Yes____No____

An Interconnection Customer interconnecting a new Small Generating Facility that plans to participate in the wholesale markets? Yes____No____

An existing Small Generating Facility commencing participation in the wholesale markets?
Yes____No____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

_____ (Local Electric Service Provider) _____ (Existing Account Number)

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Small Generating Facility Information

Interconnection Customer's Requested Initial Synchronization Date:

Interconnection Customer's Requested In-Service Date: _____

Interconnection Customer's Requested Commercial Operation Date: _____

Proposed Point of Interconnection: _____

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River): _____
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) _____

Prime Mover: ___ Fuel Cell ___ Recip Engine ___ Gas Turb ___ Steam Turb
___ Microturbine ___ PV ___ Other

Type of Generator: ___ Synchronous ___ Induction ___ Inverter

Generator Nameplate Rating: _____ kW (Typical) Generator Nameplate kVAR: _____

Interconnection Customer or Customer-Site Load: _____ kW (if none, so state)

Typical Reactive Load (if known): _____

Maximum Physical Export Capability Requested: _____ kW

Will the generator have energy storage capacity? Yes ___ No ___

If Yes, describe the energy storage device and specifications:

Provide the maximum output of each generator including each energy storage device: __

Primary frequency response operating range for electric storage resources:

Minimum State of Charge: _____

Maximum State of Charge: _____

Generating Facility Capacity (MW):

	Maximum Net MW Electrical Output	Maximum Gross MW Electrical Output
At 90 degrees F or higher		
At 50 degrees F or higher		
At 20 degrees F or higher		
At zero degrees F or higher		

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Is the prime mover compatible with the certified protective relay package? ___Yes ___No

Generator (or solar collector)

Manufacturer, Model Name & Number: _____

Version Number: _____

Nameplate Output Power Rating in kW: (Summer) _____ (Winter) _____

Nameplate Output Power Rating in kVA: (Summer) _____ (Winter) _____

Individual Generator Power Factor

Rated Power Factor: Leading: _____ Lagging: _____

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: _____ Elevation: _____ ___ Single phase ___ Three phase

Inverter Manufacturer, Model Name & Number (if used): _____

List of adjustable set points for the protective equipment or software: _____

Model Requirements

For all generation types: A completed, fully functioning, public (*i.e.*, non-proprietary or non-confidential) Siemens PTI's ("PSSE") power flow model or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flow ("PSLF") data sheet, must be supplied with this Interconnection Request. If additional public data sheets are more appropriate to the proposed device then they shall be provided and discussed at the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted.

A PSCAD model for all wind and inverter-based Small Generating Facilities must be supplied with this Interconnection Request. If a PSCAD model is deemed required for other Generating Facility types at the Scoping Meeting, such PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the executed Interconnection System Impact Study Agreement. A benchmarking analysis consistent with the requirements in the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model, shall be provided at the time the PSCAD model is submitted.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous ___ or RMS? _____

Harmonics Characteristics: _____

Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:

Generator AC resistance R_a : _____

Direct Axis Synchronous Reactance, X_d : _____ P.U.

Direct Axis Transient Reactance, X'_d : _____ P.U.

Direct Axis Subtransient Reactance, X''_d : _____ P.U.

Negative Sequence Reactance, X_2 : _____ P.U.

Zero Sequence Reactance, X_0 : _____ P.U.

KVA Base: _____

Field Volts: _____

Field Amperes: _____

Induction Generators:

Motoring Power (kW): _____

I_2^2t or K (Heating Time Constant): _____

Rotor Resistance, R_r : _____

Stator Resistance, R_s : _____

Stator Reactance, X_s : _____

Rotor Reactance, X_r : _____

Magnetizing Reactance, X_m : _____

Short Circuit Reactance, X_d'' : _____

Exciting Current: _____

Temperature Rise: _____

Frame Size: _____

Design Letter: _____

Reactive Power Required In Vars (No Load): _____

Reactive Power Required In Vars (Full Load): _____

Total Rotating Inertia, H: _____ Per Unit on kVA Base

Note: Please contact the System Operator prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ___Yes ___No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ___single phase ___three phase? Size: _____kVA

Transformer Impedance: _____% on _____kVA Base

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Secondary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Tertiary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _____ Type: _____ Size: _____ Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _____ Type: _____

Load Rating (Amps): _____ Interrupting Rating (Amps): _____ Trip Speed (Cycles): _____

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	_____	_____	_____
2.	_____	_____	_____
3.	_____	_____	_____
4.	_____	_____	_____
5.	_____	_____	_____
6.	_____	_____	_____

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Potential Transformer Data (If Applicable):

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

General Information

Enclose two copies of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Are two copies of One-Line Diagram Enclosed? ___ Yes ___ No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) _____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___ Yes ___ No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are Schematic Drawings Enclosed? ___ Yes ___ No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____ Date: _____

In order for a Small Generator Interconnection Request to be considered a valid request, it must:

- (a) Be accompanied by the applicable deposit that is provided electronically and which shall be non-refundable;
- (b) Include documentation of Site Control, if applicable;

- (c) Include a detailed map, such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures;
- (d) Include two copies, signed and stamped by a licensed Professional Engineer, of the site electrical one-line diagram; and
- (e) Include all information and data required on the Interconnection Request form and any attachments thereto.

The Interconnection Request must be submitted to the System Operator via the Interconnection Request Tracking Tool or IRTT.

Attachment A to Interconnection Request Form

SUPPLEMENTARY WIND AND INVERTER-BASED GENERATING FACILITY DATA FORM

1. Attach a Geographic Map Demonstrating the Project Layout and its Interconnection to the Power Grid. (Specify the name of the attachment here)

2. Attach a Bus-Breaker Based One-line Diagram (The diagram should include each of the individual wind unit, generator number, rating and terminal voltage.) (Specify the name of the attachment here)

2.1 Collection system detail impedance sheet

If a collector system is used, attach a collector system data sheet in accordance with the one-line diagram attached above. The data sheet should include: the type, length Z_0 , Z_1 and Xc/B of each circuit (feeder and collector string).

Specify the name of the attachment here: _____

2.2 Collection system aggregate (equivalent) model data sheet

Attach an aggregate (equivalent) collection system data sheet. The data table should include: the type, length, Z_0 , Z_1 and Xc/B of the equivalent circuits (feeders and collector strings).

Specify the name of the attachment here: _____

3. Summary of the Unit Models in the wind or inverter-based generating facility *(List all different unit models in the facility)*

Manufacturer Model	Type of this WTG* (if applicable)	Generator Unit Numbers in the field	Number(s) of these Units	Maximum Output of this Unit (MW)	Total MW

--	--	--	--	--	--

- * Type 1 – Cage rotor induction generators
- Type 2 – Induction generators with variable rotor resistance
- Type 3 – Doubly-fed asynchronous generators with rotor-side converter
- Type 4 – Full-power converter interface

Repeat the following sections from 4 to 12 for each different unit model.

4. Unit Detail Information

Unit Manufacturer Model	
Terminal Voltage	
Rating of Each Unit (MVA)	
Maximum Gross Electrical Output (MW)	
Minimum Gross Electrical Output(MW)	
Lagging Reactive Power Limit at Rated Real Power Output (MVAR)	
Leading Reactive Power Limit at Rated Real Power Output (MVAR)	
Lagging Reactive Power Limit at Zero Real Power Output (MVAR)	
Leading Reactive Power Limit at Zero Real Power Output (MVAR)	
Station Service Load(MW, MVAR)	
Minimum short circuit ratio(SCR) requirement by manufacturer	
On which bus the minimum SCR is required by manufacturer	
What voltage level the minimum SCR is required by manufacturer	
Positive sequence Xsource	
Zero sequence Xsource	

5. Unit GSU – _____

Nameplate rating (MVA)	
Total number of the GSUs	
Voltages, generator side/system side	
Winding connections, low voltage/high voltage	
Available tap positions on high voltage side	
Available tap positions on low voltage side	
Will the GSU operate as an LTC?	
Desired voltage control range if LTC	
Tap adjustment time (Tap switching delay + switching time) if LTC	
Desired tap position if applicable	
Impedance, Z1, X/R ratio	
Impedance, Z0, X/R ratio	

6. Low Voltage Ride Through(LVRT) – _____(*Specify the Manufacturer Model of this Unit*)

Does each Unit have LVRT capability?

Yes__ No__

If yes, please provide:

6.1 Unit LVRT mode activation and release condition:

When operating at maximum real power, what is the Unit terminal voltage for LVRT mode activation? _____

When operating at maximum real power, what is the Unit terminal voltage for releasing LVRT mode after it is activated? _____

If there is different LVRT activation and release logic, please state here _____

6.2 A wind or inverter-based generating facility technical manual from the manufacturer including description of LVRT functionality:

Attach the file and specify the name of the attachment here:

6.3 Does the wind or inverter-based generating facility technical manual attached above include a reactive power capability curve?

Yes__ No__

If no, attach the file and specify the name of the attachment here:

7. Low Voltage Protection (considering LVRT functionality)

(Specify the Manufacturer Model of this Unit)

Low Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

8. High Voltage Protection - _____(Specify the Manufacturer Model of this Unit)

High Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

9. Low Frequency Protection - _____(Specify the Manufacturer Model of this Unit)

Low Frequency Setting (Hz)	Relay Pickup Time (Seconds)

--	--

*Add more rows in the table as needed

10. High Frequency Protection - _____ (Specify the Manufacturer Model of this Unit)

High Frequency Setting (Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

Please make sure the settings in sections 7 through 10 comply with NERC and NPCC standards for generator protection relays.

11. Unit Reactive Power Control - _____ (Specify the Manufacturer Model of this Unit)

11.1 What are the options for the Unit reactive power control (check all available)?

- ____ Control the voltage at the Unit terminal
- ____ Control constant power factor at the Unit terminal
- ____ Control constant power factor at the low side of the station main transformer
- ____ Control constant power factor at the high side of the station main transformer
- ____ Control voltage at the low side of the station main transformer
- ____ Control voltage at the high side of the station main transformer
- ____ Other options. Please describe if select others

11.2 In all the control options selected above, please list the options in which the Unit is able to control its terminal voltage to prevent low/high voltage tripping.

11.3 What is the desired control mode from the selected options above? Specify the control plan in this mode. For example: control voltage at which bus to what schedule.

12. Wind or inverter-based generating facility Model

(All model files provided under this section 12 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

12.1 Power flow model

12.1.1 A *. RAW file including **aggregated/equivalent** wind or inverter-based generating facility power flow model with appropriate parameters and settings.

*Attach the *.RAW file and specify the name of the attachment here:*

12.1.2 A *. RAW file including **detailed** wind or inverter-based generating facility power flow model with appropriate parameters and settings. *(Optional)*

*Attach the *.RAW file and specify the name of the attachment here:*

12.2 Dynamic simulation model

(Please note that the dynamic model must match the aggregated/equivalent power flow model provided above. Attach the following information for each of the models.)

12.2.1 Wind or inverter-based generating facility Model _____(Please Specify the Manufacturer Model)

12.2.2 A compiled PSS/E dynamic model for the turbines (a *.LIB or *.OBJ file)

*Attach the *.LIB or *.OBJ file and specify the name of the attachment here:*

12.2.3 A dynamic data file with appropriate parameters and settings for the turbines (typically a *.DYZ file)

Attach the *.DYZ file and specify the name of the attachment here:

12.2.4 PSS/E wind or inverter-based generating facility model user manual for the WTG

Attach and specify the name of the attachment here:

Repeat the above sections from 6 to 12 for each different wind or inverter-based generating facility model.

13. Power Plant Controller

Will the wind or inverter-based generating facility be equipped with power plant controller, which has the ability to centrally control the output of the units?

Yes__ No__

If yes, please provide:

13.1 Manufacturer model of the power plant controller

13.2 What are the reactive power control strategy options of the power plant controller?

13.3 Which of the control option stated above is being used in current operation?

13.3 Is the power plant controller able to control the unit terminal voltages to prevent low/high voltage tripping?

Yes__ No__

Please provide the park controller technical manual from the manufacturer

Attach the file and specify the name of the attachment here:

14. Station Transformer

Transformer Name		
Nameplate ratings (MVA)		
Total number of the main transformer(s)		
Voltages, High/Low/Tertiary (kV)		
Winding connections, High/Low/Tertiary		
Available tap positions on high voltage side		
Available tap positions on low voltage side		
Will the transformer operate as a LTC?		
Desired voltage control range if LTC		
Tap adjustment time (Tap switching delay + switching time) if LTC		
Desired tap position if applicable		
Tap adjustment time (Tap switching delay + switching time)		
Impedance Z_1 , X/R ratio	Z_{1H-L}	X/R
	Z_{1H-T}	X/R
	Z_{1T-L}	X/R
Impedance Z_0 , X/R ratio	Z_{0H-L}	X/R
	Z_{0H-T}	X/R
	Z_{0T-L}	X/R

15. Dynamic Simulation Model for the Power Plant Controller(s) (if applicable)

(All model files provided under this section 15 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

15.1 A compiled PSS/E dynamic model for the power plant controller(s) (a *.LIB or *.OBJ file)

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

- 15.2 A dynamic data file with appropriate parameters and settings for the power plant controller(s) (typically a *.DYR file).

Please set the parameters in accordance with the currently used control mode.

*Attach the *.DYR file and specify the name of the attachment here:*

- 15.3 PSS/E model user manual for the power plant controller(s)

Attach the manual and specify the name of the attachment or specify the name of the attachment here: _____

16. Capacitors and Reactors

Please provide necessary modeling data for all the capacitors and reactors belong to the facility, including: size, basic electrical parameters, connecting bus, switched or fixed, etc.

17. Dynamic Device(s)

(All model files provided under this section 17 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

- 17.1 Provide necessary modeling data file for all the dynamic devices belong to the facility.

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

- 17.2 A dynamic data file containing the parameters for the units (typically a *.DYR file).

Set the parameters in accordance with the desired control mode.

Attach the *.DYR file and specify the name of the attachment here:

18. Collection System/Transformer Tap-Setting Design

Attach a collection system/transformer tap-setting design calculations, consistent with the requirements in the ISO New England Planning Procedures, that identify the calculations to

support the proposed tap settings for the unit step-up transformers and the station step-up transformers.

Attach the design document and specify the name of the attachment here:

19. Additional Information

Are there any special features available to be implemented to the wind or inverter-based generating facility? Such as weak grid interconnection solutions, etc.

Specify the available features here:

Insert the technical manual for each of the features listed above as objects (display as icons) or specify the name of the attachment

here: _____

20. Provide PSCAD Model and Documentation for the wind or inverter-based generating facility, the Power Plant Controller(s) and Other Dynamic Devices for the wind or inverter-based generating facility.

ISO will determine how much PSCAD work is needed from the wind or inverter-based generating facility based on its interconnection system conditions.

CLUSTER SYSTEM IMPACT STUDY APPLICATION FORM

The undersigned Interconnection Customer submits this form to request the inclusion of the Interconnection Request for its Small Generating Facility in a Cluster Interconnection System Impact Study pursuant to Section 1.5.3.3.2.2 of this SGIP.

To be included in a Cluster Interconnection System Impact Study, the following must be submitted together with this form to the System Operator by the Cluster Entry Deadline:

1. Project Information:

a. Project Name: _____

b. Queue Position: _____

c. Is the Interconnection Request contractually associated with another Interconnection Request for an Elective Transmission Upgrade? Yes ____ No ____

If yes, identify Queue Position of the associated Interconnection Request and provide evidence of the contractual commitment. Queue Position No.: _____

2. Initial Cluster Participation Deposit as specified in Section 1.5.3.3.2.2.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this form is true and accurate.

For Interconnection Customer: _____ Date: _____

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Certification of Small Generator Equipment Packages

- 1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.
- 2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
- 3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.
- 4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

- 5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.
- 6.0 An equipment package does not include equipment provided by the utility.
- 7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

10 kW Inverter Process

Solely applicable for Network Resource Interconnection Service

- 1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the System Operator.
- 2.0 The System Operator acknowledges to the Customer receipt of the Application within three Business Days of receipt.
- 3.0 The System Operator in conjunction with the Interconnecting Transmission Owner evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.
- 4.0 The System Operator in conjunction with the Interconnecting Transmission Owner verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The System Operator has 15 Business Days to complete this process. Unless the System Operator in conjunction with the Interconnecting Transmission Owner determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the System Operator approves the Application and returns it to the Customer. Note to Customer: Please check with the System Operator before submitting the Application if disconnection equipment is required.
- 5.0 After installation, the Customer returns the Certificate of Completion to the System Operator. Prior to parallel operation, the System Operator and Interconnecting Transmission Owner may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.
- 6.0 The System Operator in conjunction with the Interconnecting Transmission Owner notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Interconnecting Transmission Owner has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Interconnecting Transmission Owner is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Interconnecting Transmission Owner does not

inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

- 7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the System Operator and the Interconnecting Transmission Owner, that contact information must be provided on the Application.
- 8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.
- 9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.4, documentation of Site Control must be submitted with the Interconnection Request, except where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of \$100 must accompany this Application.

Interconnection Customer

Name: _____

Contact Person: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Contact (if different from Interconnection Customer)

Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Owner of the facility (include % ownership by any electric utility): _____

Small Generating Facility Information

Location (if different from above): _____

Electric Service Company: _____

Account Number: _____

Is the Interconnection Request for:

A retail customer interconnecting a new Small Generating Facility that will produce electric energy to be consumed only on the retail customer’s site? Yes____No____

A Qualifying Facility where 100% of the output will be sold to its host utility?
Yes____No____

An Interconnection Customer interconnecting a new Small Generating Facility that plans to participate in the wholesale markets? Yes____No____

An existing Small Generating Facility commencing participation in the wholesale markets?
Yes____No____

Inverter Manufacturer:_____Model_____

Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)

Single Phase _____ Three Phase_____

System Design Capacity: _____ (kW) _____ (kVA)

Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell

Turbine Other _____

Energy Source: Solar Wind Hydro Diesel Natural Gas

Fuel Oil Other (describe) _____

Is the equipment UL1741 Listed? Yes____No____

If Yes, attach manufacturer’s cut-sheet showing UL1741 listing

Estimated Installation Date: _____ Estimated In-Service Date: _____

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small

Generator Interconnection Procedures (SGIP), or the Interconnecting Transmission Owner has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: _____

Title: _____ Date: _____

**Contingent Approval to Interconnect the Small Generating Facility
(For Internal use only)**

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Interconnecting Transmission Owner Signature: _____

Title: _____ Date: _____

Application ID number: _____

Interconnecting Transmission Owner waives inspection/witness test? Yes ___ No ___

System Operator Signature: _____

Title: _____ Date: _____

Application ID number: _____

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes _____ No _____

Interconnection Customer: _____

Contact Person: _____

Address: _____

Location of the Small Generating Facility (if different from above):

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Electrician:

Name: _____

Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

License number: _____

Date Approval to Install Facility granted by the Interconnecting Transmission Owner: _____

Application ID number: _____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local building/electrical code of _____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Print Name: _____

Date: _____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert System Operator and Interconnecting Transmission Owner information below):

Name: _____

System Operator: _____

Address: _____

City, State ZIP: _____

Fax: _____

Name: _____

Interconnecting Transmission Owner:

Address: _____

City, State ZIP: _____

Fax: _____

Approval to Energize the Small Generating Facility

(For Internal use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Interconnecting Transmission Owner Signature: _____

Title: _____ Date: _____

System Operator Signature: _____

Title: _____ Date: _____

**Terms and Conditions for Interconnecting an Inverter-Based
Small Generating Facility No Larger than 10kW**

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the System Operator approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Interconnecting Transmission Owner's (the "Company") electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the System Operator and the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small

Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 **Safe Operations and Maintenance**

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 **Access**

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 **Disconnection**

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 **Insurance**

The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

9.1 By the Customer

9.2 By providing written notice to the Company and the System Operator.

9.3 By the Company or the System Operator

9.4 If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

10.0 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

11.0 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require any Party to fulfill rights or obligations that arose under the Agreement.

12. **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the System Operator and the Company.

Interconnection Feasibility Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and _____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on _____; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Administered Transmission System; and

WHEREAS, Interconnection Customer has requested the System Operator and Interconnecting Transmission Owner to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility with the facilities that are part of the Interconnecting Transmission Owner's Administered Transmission System, and of any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures ("SGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection Feasibility Study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.
- 4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the Interconnection Feasibility Study may be extended by agreement of the Parties.
- 5.0 In performing the study, the System Operator and Interconnecting Transmission Owner shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the Interconnection Feasibility Study.
- 6.0 The Interconnection Feasibility Study report shall provide the following analyses depending on whether the Feasibility Study consisted of: (a) a power flow, including thermal analysis and voltage analysis, and short circulated analysis, or (b) limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the interconnection of the Small Generating Facility as proposed given recent study experience and as discussed at the Scoping Meeting:
 - 6.1 Initial identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection, or, findings of the limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient

analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;

- 6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;
 - 6.3 Preliminary description of and a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study;
 - 6.4 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, initial review of grounding requirements and electric system protection;
 - 6.5 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues and length of time that would be necessary to construct the facilities; and
 - 6.6 To the extent the Interconnection Customer requested a preliminary analysis as described in Section 3.3.2 of the SGIP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.
- 7.0 The Interconnection Feasibility Study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

- 8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.
- 9.0 A deposit, paid to the System Operator, of the lesser of 50 percent of good faith estimated Interconnection Feasibility Study costs or earnest money of \$1,000 shall be required from the Interconnection Customer.
- 10.0 Once the Interconnection Feasibility Study is completed, an Interconnection Feasibility Study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the Interconnection Feasibility Study must be completed and the Interconnection Feasibility Study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct an Interconnection Feasibility Study.
- 11.0 The total estimated cost of the performance of the Interconnection Feasibility Study consists of \$ [insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted. 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator shall refund such excess within 30 calendar days of the invoice without interest.
- 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator shall refund such excess within 30 calendar days of the invoice without interest
- 13.0 Miscellaneous.
- 13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Feasibility Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection Feasibility Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection Feasibility Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection Feasibility Study, the content of the Interconnection Feasibility Study, or the conclusions of the Interconnection Feasibility Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

13.3 Force Majeure, Liability and Indemnification.

13.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

13.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System

Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

- 13.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case

of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 13.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 13.2 and 13.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection Feasibility Study shall not be deemed third party beneficiaries of Sections 13.2 and 13.3.
- 13.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 13.5, shall continue in effect for a term of one year or until the Interconnection Feasibility Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.

- 13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.
- 13.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 13.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 13.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 13.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 13.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other

failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

- 13.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.
- 13.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 13.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 13.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the

hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

13.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

13.16 Reservation of Rights. Subject to the TOA, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator]

[Insert name of Interconnection Customer]

Signed _____

Name (Printed):

Title _____

Signed _____

Name (Printed):

Title _____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to
Interconnection Feasibility Study Agreement**

Assumptions Used in Conducting the Interconnection Feasibility Study

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on _____:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer, System Operator and Interconnecting Transmission Owner.

Interconnection System Impact Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and
_____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
Administered Transmission System;

WHEREAS, the System Operator and Interconnecting Transmission Owner have completed an
Interconnection Feasibility Study and provided the results of said study to the Interconnection Customer
(This recital to be omitted if the Parties have agreed to forego the Interconnection Feasibility Study.); and

WHEREAS, the Interconnection Customer has requested the System Operator and Interconnecting
Transmission Owner to perform an Interconnection System Impact Study(s) to assess the impact of
interconnecting the Small Generating Facility with the facilities that are part of the Interconnecting
Transmission Owner's Administered Transmission System, and of any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

- 1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.
- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection System Impact Study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of an Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.
- 4.0 An Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request. The System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.
- 5.0 An Interconnection System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. An Interconnection System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. An Interconnection System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and

time to construct.

- 6.0 A distribution Interconnection System Impact Study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.
- 7.0 Affected Systems may participate in the preparation of an Interconnection System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon an Interconnection System Impact Study that covers potential adverse system impacts on their electric systems, and the System Operator and Interconnecting Transmission Owner have 20 additional Business Days to complete an Interconnection System Impact Study requiring review by Affected Systems.
- 8.0 If the System Operator uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the Interconnection System Impact Study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced.
 - 8.1 Are directly interconnected with the Administered Transmission System; or
 - 8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and
 - 8.3 Have a pending higher queued Interconnection Request to interconnect with the Administered Transmission System.
- 9.0 A distribution Interconnection System Impact Study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission Interconnection System Impact Study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer; and the one half the good faith estimated cost of a transmission Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer.

11.0 The total estimated cost of the performance of the Interconnection System Impact Study consists of \$[insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator or Interconnecting Transmission Owner, as applicable, shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Miscellaneous.

13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection System Impact Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection System Impact Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection System Impact Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied,

whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection System Impact Study, the content of the Interconnection System Impact Study, or the conclusions of the Interconnection System Impact Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

13.3 Force Majeure, Liability and Indemnification.

13.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

13.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission

Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

13.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of

Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 13.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 13.2 and 13.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection System Impact Study shall not be deemed third party beneficiaries of Sections 13.2 and 13.3.
- 13.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 13.5, shall continue in effect for a term of one year or until the Interconnection System Impact Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.
- 13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____(where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be

deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.

- 13.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 13.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 13.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 13.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 13.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.
- 13.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the

Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.

- 13.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 13.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 13.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.
- 13.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.
- 13.16 Reservation of Rights. Subject to the TO Agreement, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any

other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator] [Insert name of Interconnection Customer]

Signed _____

Name (Printed):

Title _____

Signed _____

Name (Printed):

Title _____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to System
Impact Study Agreement**

Assumptions Used in Conducting the System Impact Study

The Interconnection System Impact Study shall be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer, System Operator and Interconnecting Transmission Owner.

Interconnection Facilities Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and
_____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
Administered Transmission System;

WHEREAS, the System Operator and Interconnecting Transmission Owner have completed an
Interconnection System Impact Study and provided the results of said study to the Interconnection
Customer; and

WHEREAS, the Interconnection Customer has requested the System Operator and Interconnecting
Transmission Owner to perform an Interconnection Facilities Study to specify and estimate the cost of the
equipment, engineering, procurement and construction work needed to implement the conclusions of the
Interconnection System Impact Study in accordance with Good Utility Practice to physically and
electrically connect the Small Generating Facility with the facilities that are part of the Interconnecting
Transmission Owner's Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

- 1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures, or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”).
- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause an Interconnection Facilities Study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of the Interconnection Facilities Study shall be subject to data provided in Attachment A to this Agreement.
- 4.0 The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the Interconnection System Impact Study(s). The Interconnection Facilities Study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Interconnecting Transmission Owner’s Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.
- 5.0 The System Operator and Interconnecting Transmission Owner may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.
- 6.0 A deposit, paid to the System Operator, of the good faith estimated Interconnection Facilities Study costs shall be required from the Interconnection Customer.
- 7.0 In cases where Upgrades are required, the Interconnection Facilities Study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are

necessary, and the required facilities are limited to Interconnection Facilities, the Interconnection Facilities Study must be completed within 30 Business Days.

- 8.0 Once the Interconnection Facilities Study is completed, an Interconnection Facilities Study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the Interconnection Facilities Study must be completed and the Interconnection Facilities Study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct an Interconnection Facilities Study.
- 9.0 The total estimated cost of the performance of the Interconnection Facility Study consists of \$ [insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.
- 10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator or Interconnecting Transmission Owner, as applicable, shall refund such excess within 30 calendar days of the invoice without interest.
- 11.0 Miscellaneous.
- 11.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.
- 11.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Facilities Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly,

beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection Facilities Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection Facilities Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection Facilities Study, the content of the Interconnection Facilities Study, or the conclusions of the Interconnection Facilities Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

11.2 Force Majeure, Liability and Indemnification.

11.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

11.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection

Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

11.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by

Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 11.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 11.2 and 11.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection Facilities Study shall not be deemed third party beneficiaries of Sections 11.2 and 11.3.
- 11.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 11.5, shall continue in effect for a term of one year or until the Interconnection Facilities Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.
- 11.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____(where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek

changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

- 11.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.
- 11.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 11.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 11.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 11.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 11.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an

interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

- 11.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.
- 11.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 11.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 11.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

11.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

11.16 Reservation of Rights. Subject to the TOA, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator] **[Insert name of Interconnection Customer]**

_____	_____
Signed_____	Signed_____
Name (Printed):	Name (Printed):
_____	_____
Title_____	Title_____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to
Interconnection Facilities Study Agreement**

**Data to Be Provided by the Interconnection Customer
with the Interconnection Facilities Study Agreement**

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location.
(Maximum load on Current Transformer/Power Transformer (“CT/PT”))

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT)
Amps

One set of metering is required for each generation connection to the new ring bus or existing
Transmission Provider station. Number of generation connections: _____

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes ____ No ____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the
total plant generation? Yes ____ No ____
(Please indicate on the one-line diagram).

What type of control system or Power Line Carrier (“PLC”) will be located at the Small Generating
Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Administered Transmission System.

Tower number observed in the field. (Painted on tower leg)*:

Number of third party easements required for transmission lines*:

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?

Yes _____ No _____ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction Date: _____

Generator step-up transformers
receive back feed power Date: _____

Generation Testing Date: _____

Commercial Operation Date: _____

**STANDARD SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)**

TABLE OF CONTENTS

Article. 1. Scope and Limitations of Agreement

- 1.1 Applicability
- 1.2 Purpose
- 1.3 No Agreement to Purchase or Deliver Power
- 1.4 Limitations
- 1.5 Responsibilities of the Parties
- 1.6 Parallel Operation Obligations
- 1.7 Metering
- 1.8 Reactive Power and Primary Frequency Response
- 1.9 Capitalized Term
- 1.10 Scope of Service

Article. 2. Inspection, Testing, Authorization, and Right of Access

- 2.1 Equipment Testing and Inspection
- 2.2 Authorization Required Prior to Parallel Operation
- 2.3 Right of Access

Article. 3. Effective Date, Term, Termination, and Disconnection

- 3.1 Effective Date
- 3.2 Term of Agreement
- 3.3 Termination
- 3.4 Temporary Disconnection
 - 3.4.1 Emergency Conditions
 - 3.4.2 Routine Maintenance, Construction, and Repair
 - 3.4.3 Forced Outages
 - 3.4.4 Adverse Operating Effects
 - 3.4.5 Modification of the Small Generating Facility
 - 3.4.6 Reconnection

Article. 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

- 4.1 Interconnection Facilities
- 4.2 Distribution Upgrades

Article. 5. Cost Responsibility for Network Upgrades

- 5.1 Applicability

- 5.2 Network Upgrades
- 5.3 Special Provisions for Affected Systems
- 5.4 Rights Under Other Agreements

Article.6. Billing, Payment, Milestones, and Financial Security

- 6.1 Billing and Payment Procedures and Final Accounting
- 6.2 Milestones
- 6.3 Financial Security Arrangements

Article. 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

- 7.1 Assignment
- 7.2 Limitation of Liability
- 7.3 Indemnity
- 7.4 Consequential Damages
- 7.5 Force Majeure
- 7.6 Default

Article. 8. Insurance Requirements

- 8.1 General Liability
- 8.2 Insurer Requirements and Endorsements
- 8.3 Evidence of Insurance
- 8.4 Self Insurance
- 8.5 Interconnecting Transmission Owner Insurance

Article. 9. Confidentiality

Article. 10. Disputes

Article. 11. Taxes

Article. 12. Miscellaneous

- 12.1 Governing Law, Regulatory Authority, and Rules
- 12.2 Amendment
- 12.3 No Third-Party Beneficiaries
- 12.4 Waiver
- 12.5 Entire Agreement
- 12.6 Multiple Counterparts
- 12.7 No Partnership
- 12.8 Severability
- 12.9 Security Arrangements

12.10 Environmental Releases

12.11 Subcontractors

12.12 Reservation of Rights

Article. 13. Notices

13.1 General

13.2 Billing and Payment

13.3 Alternative Forms of Notice

13.4 Designated Operating Representative

13.5 Changes to the Notice Information

Article. 14. Signatures

Attachments to SGIA

Attachment 1 – Glossary of Terms

Attachment 2 – Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Attachment 3 – One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4 – Milestones

Attachment 5 – Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs

Attachment 6 – Interconnecting Transmission Owner's Description of its Upgrades and Best Estimate of Upgrade Costs

Attachment 7 – Commercial Operation Date

THIS STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT ("Agreement")

is made and entered into this _____ day of _____, 20__, by and between _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ (“Interconnection Customer” with a Small Generating Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware (“System Operator”), and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ (“Interconnecting Transmission Owner”). Under this Agreement the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a “Party” or collectively as the “Parties.”

In consideration of the mutual covenants set forth herein, the Parties agree as follows

Article 1. Scope and Limitations of Agreement

1.1 Applicability:

This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 Purpose

This Agreement governs the terms and conditions under which the Interconnection Customer’s Small Generating Facility will interconnect with, and operate in parallel with, the Interconnecting Transmission Owner’s facilities that are part of the Administered Transmission System.

1.3 No Agreement to Purchase or Deliver Power

This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Party.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement between the Parties.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Interconnecting Transmission Owner shall construct, operate, and maintain its transmission facilities and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their

respective sides of the point of change of ownership. The Interconnecting Transmission Owner and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the New England Transmission System [or Interconnecting Transmission Owner's transmission facilities], personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

- 1.5.6 The System Operator, with input from the Interconnecting Transmission Owner, shall coordinate with all Affected Systems to support the interconnection.
- 1.5.7 The Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 2.1 of this Agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The Small Generating Facility's protective equipment settings shall comply with the Interconnecting Transmission Owner's automatic load-shed program. The System Operator and Interconnecting Transmission Owner shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The term “frequency ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting

Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The term “voltage ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to the ISO New England Operating Documents, and the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Interconnecting Transmission Owner’s reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachment 2 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power and Primary Frequency Response

1.8.1 Power Factor Design Criteria

1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection with dynamic reactive capability over the power factor range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all similarly situated synchronous (and non-wind non-synchronous generators as specified in Appendix G, Section A.ii.4, to the LGIA) generators on a comparable basis and in accordance with Operating Requirements.

1.8.1.2 Non-Synchronous Generation. Generating Facilities shall be subject to the power factor design criteria specified in Appendix G to the LGIA. Wind and inverter-based Generating Facilities shall be subject to the Low Voltage Ride-Through Capability requirements specified in Appendix G to the LGIA.

1.8.2 Interconnection Customers shall be compensated for reactive power service in accordance with Schedule 2 of the Tariff.

1.8.3 Primary Frequency Response

Interconnection Customer with an Interconnection System Impact Study that commenced before May 15, 2018 is obligated to provide and maintain a functioning governor on all generating units comprising the Small Generating Facility in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnection Customer with an Interconnection System Impact Study that commenced on or after May 15, 2018 shall ensure the primary frequency response capability of its Small Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a

maximum 5 percent droop and ± 0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based on an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Small Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify System Operator and Interconnecting Transmission Owner that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the New England Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Articles 1.8.3.1 and 1.8.3.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities.

1.8.3.1 Governor or Equivalent Controls. Whenever the Small Generating Facility is operated in parallel with the New England Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with System Operator and Interconnecting Transmission Owner, set the deadband parameter to: (1) a maximum of ± 0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability

Standard that provides for equivalent or more stringent parameters.

Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to System Operator and Interconnecting Transmission Owner upon request. If Interconnection Customer needs to operate the Small Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify System Operator and Interconnecting Transmission Owner, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Small Generating Facility's governor or equivalent controls to a minimum whenever the Small Generating Facility is operated in parallel with the New England Transmission System.

1.8.3.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Small Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

1.8.3.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Articles 1.8.3, 1.8.3.1, and 1.8.3.2 of this Agreement. Small Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Article 1.8.3, but shall be otherwise exempt from the operating requirements in Articles 1.8.3, 1.8.3.1, 1.8.3.2, and 1.8.3.4 of this Agreement.

1.8.3.4 Electric Storage Resources. Interconnection Customer interconnecting a Small Generating Facility that is an electric storage resource shall establish an operating range in Attachment 5 of its SGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Articles 1.8.3, 1.8.3.1, 1.8.3.2 and 1.8.3.3 of this Agreement. Attachment 5 shall specify whether the operating range is static or dynamic, and shall consider: (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by System Operator, Interconnecting Transmission Owner and Interconnection Customer. If the operating range is dynamic, then Attachment 5 must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Article 1.8.3.2 of this Agreement when it is online and dispatched to inject electricity to the New England Transmission System and/or receive electricity from the New England Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the New England Transmission System and/or dispatched to receive electricity from the New England Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement. Capitalized terms in Schedule 23 that are not defined in the Glossary of Terms shall have the meanings specified in Sections I.2.2. of the Tariff.

1.10 Scope of Service

1. 10.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

NR for NR Interconnection Service (NR Capability Only)

CNR for CNR Interconnection Service (NR Capability and CNR Capability)

1.10.1.1 Capacity Network Resource Interconnection Service (CNR Interconnection Service)

- (a) The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and the Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which all other CNRs are interconnected under the CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Small Generating Facility to be designated as a CNR to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the net CNR Capability, or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as all other existing Capacity Network Resources, and to be studied as a Capacity Network Resource on the assumption that such a designation will occur.

1.10.1.2 Network Resource Interconnection Service (NR Interconnection Service).

- (a) The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which all other Network Resources are interconnected under the NC Interconnection Standard.

NR Interconnection Service allows the Interconnection Customer's Small Generating Facility to participate in the New England Markets, in accordance with Market Rule, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule 1, Section III of the Tariff. Notwithstanding the above, the portion of a Small Generating Facility that has been designated as a Network Resource interconnected under the NC Interconnection Standard cannot be a capacity resource under Section III.13 of the Tariff, except pursuant to a new Interconnection Request for CNR Interconnection Service.

- 1.10.1.3 Provision of Service. System Operator and Interconnecting Transmission Owner shall provide Interconnection Service for the Small Generating Facility at the Point of Interconnection.
- 1.10.1.4 Performance Standards. Each Party shall perform all of its obligations under this SGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this SGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the SGIA and System Operator, in conjunction with the Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.
- 1.10.1.5 No Transmission Service Delivery. The execution of this SGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.
- 1.10.1.6 Transmission Delivery Service Implications. CNR Interconnection Service and NR Interconnection Service allow the Interconnection Customer's Small Generating Facility to be designated by any Network Customer under the Tariff on the New England Transmission System as a Capacity Network Resource or Network Resource, up to the net CNR Capability or NR Capability, respectively, on the same basis as all other existing Capacity Network Resources and Network Resources interconnected to the New England Transmission System, and to be studied as a Capacity Network Resource or a Network Resource on the assumption that such a designation will occur. Although CNR Interconnection Service and NR Interconnection

Service do not convey a reservation of transmission service, any Network Customer can utilize its network service under the Tariff to obtain delivery of capability from the Interconnection Customer's Small Generating Facility in the same manner as it accesses Capacity Network Resources and Network Resources. A Small Generating Facility receiving CNR Interconnection Service or NR Interconnection Service may also be used to provide Ancillary Services, in accordance with the Tariff and Market Rule 1, after technical studies and/or periodic analyses are performed with respect to the Small Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Capacity Network Resource or Network Resource. However, if an Interconnection Customer's Small Generating Facility has not been designated as a Capacity Network Resource or as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all Generating Facilities that are similarly situated.

CNR Network Interconnection Service and NR Interconnection Service do not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Small Generating Facility to any particular load on the New England Transmission System without incurring congestion costs. In the event of transmission constraints on the New England Transmission System, the Interconnection Customer's Small Generating Facility shall be subject to the applicable congestion management procedures for the New England Transmission System in the same manner as other Capacity Network Resources or Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that the Interconnection Customer's Small Generating Facility be designated as a Capacity Network Resource or as a Network Resource by a Network Customer under the Tariff or that the Interconnection Customer identify a specific buyer (or sink). To the extent a Network

Customer does designate the Small Generating Facility as either a Capacity Network Resource or a Network Resource, it must do so pursuant to the Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining CNR Interconnection Service or NR Interconnection Service, as long as the Small Generating Facility has not been deemed to be retired, any future transmission service request for delivery from the Small Generating Facility on the New England Transmission System of any amount of capacity capability and/or energy capability will not require that any additional studies be performed or that any further upgrades associated with such Small Generating Facility be undertaken, regardless of whether or not such Small Generating Facility is ever designated by a Network Customer as a Capacity Network Resource or Network Resource and regardless of changes in ownership of the Small Generating Facility. To the extent the Interconnection Customer enters into an arrangement for long-term transmission service for deliveries from the Small Generating Facility outside the New England Transmission System, or if the unit has been deemed to be retired, such request may require additional studies and upgrades in order for Interconnecting Transmission Owner to grant such request.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

- 2.1.1. The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the System Operator and the Interconnecting Transmission Owner of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Interconnecting Transmission Owner may, at its own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe

the testing. The Interconnection Customer shall provide the Interconnecting Transmission Owner a written test report when such testing and inspection is completed.

2.1.2 The Interconnecting Transmission Owner shall provide the Interconnection Customer and the System Operator written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Interconnecting Transmission Owner of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Interconnecting Transmission Owner [and System Operator] shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Interconnecting Transmission Owner shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Interconnecting Transmission Owner shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the New England Transmission System [or Interconnecting Transmission Owner's transmission facilities] without prior written authorization of the Interconnecting Transmission Owner. The Transmission Provider will provide such authorization once the Transmission Provider receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Interconnecting Transmission Owner may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small

Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Interconnecting Transmission Owner at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Interconnecting Transmission Owner shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. System Operator and Interconnecting Transmission Owner shall promptly file this Agreement with the Commission upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and by mutual agreement of the Parties shall remain in effect for a period of ____ years, (Term to be specified in individual Agreements, but in no case should the term be less than ten years from the Effective Date or such other longer period as the Interconnection Customer may request) and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with the Commission of a notice of termination of this Agreement (if required), which notice has been accepted for filing by the Commission.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the System Operator and Interconnecting Transmission Owner 20 Business Days written notice.

3.3.2 Each Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the Interconnecting Transmission Owner's Interconnection Facilities. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this SGIA or such non-terminating Party otherwise is responsible for these costs under this SGIA.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

“Emergency Condition” shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission Owner, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New England Transmission System, the Interconnecting Transmission Owner’s Interconnection Facilities or any Affected System to which the New England Transmission System is directly connected; or (3) that, in the case of the Interconnection Customer, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. The System Operator and the Interconnecting Transmission Owner may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility in accordance with applicable provisions of the Operating Requirements. The System Operator and Interconnecting Transmission Owner shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the New England Transmission System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

3.4.2.1 **Outage Authority and Coordination.** The System Operator shall have the authority to coordinate facility outages in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party’s(ies’) facilities

as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

3.4.2.2 Outage Schedules. Outage scheduling, and any related compensation, shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

3.4.2.3 Interruption of Service. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the System Operator or Interconnecting Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect System Operator's or Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.

3.4.3 Forced Outages

During any forced outage, the Interconnecting Transmission Owner [and the System Operator] may suspend interconnection service to effect immediate repairs on the New England Transmission System. The Interconnecting Transmission Owner shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Interconnecting Transmission Owner shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Interconnecting Transmission Owner shall notify the Interconnection Customer and the System Operator as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other

customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the New England Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Interconnecting Transmission Owner may disconnect the Small Generating Facility. The Interconnecting Transmission Owner shall provide the Interconnection Customer and the System Operator with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from: (1) the Interconnecting Transmission Owner before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the Interconnecting Transmission Owner's Interconnection Facilities; and (2) the System Operator before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the New England Transmission System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the System Operator's or the Interconnecting Transmission Owner's, as appropriate, prior written authorization, the latter shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the New England Transmission System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Interconnecting Transmission Owner shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Interconnecting Transmission Owner.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Interconnecting Transmission Owner's Interconnection Facilities.

4.2 Distribution Upgrades

The Interconnecting Transmission Owner shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Interconnecting Transmission Owner and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer shall be responsible for its share of all reasonable expenses, associated with operating, maintaining, repairing, and replacing such Distribution Upgrades, except to the extent that a retail tariff of, or an agreement with, the Interconnecting Transmission Owner or its distribution company affiliate, if appropriate, provides otherwise.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades, including Stand Alone Network Upgrades.

5.2 Network Upgrades

The Interconnecting Transmission Owner shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Interconnecting Transmission Owner and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Interconnecting Transmission Owner elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne by the Interconnection Customer.

5.2.1.1 Cost Allocation. Cost allocation of Generator Interconnection Related Upgrades shall be in accordance with Schedule 11 of Section II of the Tariff.

5.2.1.2 Compensation. Any compensation due to the Interconnection Customer for increases in transfer capability to the PTF resulting from its Generator Interconnection Related Upgrade shall be determined in accordance with Sections II and III of the Tariff.

5.3 Special Provisions for Affected Systems

The Interconnection Customer shall enter into separate related facilities agreements to address any upgrades to the Affected System(s) that are necessary for safe and reliable interconnection of the Interconnection Customer's Small Generating Facility.

5.4 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result

of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Interconnecting Transmission Owner shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties.

6.1.2 Within three months of completing the construction and installation of the Interconnecting Transmission Owner's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Transmission Provider shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Interconnecting Transmission Owner for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Interconnecting Transmission Owner shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Interconnecting Transmission Owner within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Interconnecting Transmission Owner shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by

agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party(ies) of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Interconnecting Transmission Owner's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Interconnecting Transmission Owner a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Interconnecting Transmission Owner in accordance with Section 7 of Schedule 11 of the Tariff. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Interconnecting Transmission Owner's Interconnection Facilities and Upgrades. In addition:

- 6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Interconnecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.
- 6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Interconnecting Transmission Owner and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

Notwithstanding any other provision of this Agreement, the liability, indemnification and insurance provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnection Transmission Owner and the liability, indemnification and insurance provisions of the Tariff apply to the relationship between the System Operator and the Interconnection Customer and between the Interconnecting Transmission Owner and the Interconnection Customer.

7.1 Assignment

This Agreement may be assigned by a Party upon 15 Business Days prior written notice and opportunity to object by the other Parties; provided that:

- 7.1.1 The Parties may assign this Agreement without the consent of the other Parties to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the other Parties of any such assignment.
- 7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Interconnecting Transmission Owner or the System Operator, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Interconnecting Transmission Owner and the System Operator of any such assignment.
- 7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Party(ies) for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall a Party be liable to another Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 Each Party shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's(ies') action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall

notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, in no event shall a Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party(ies), either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party(ies) informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this

Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party(ies). Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party(ies) shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance Requirements

8.1 General Liability

The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment

being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Interconnecting Transmission Owner, except that the Interconnection Customer shall show proof of insurance to the Interconnecting Transmission Owner no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 Insurer Requirements and Endorsements

All required insurance shall be carried by reputable insurers qualified to underwrite insurance in the state where the interconnection is located having a Best Rating of “A-”. In addition, all insurance shall, (a) include Interconnecting Transmission Owner and System Operator as additional insureds; (b) contain a severability of interest clause or cross-liability clause; (c) provide that Interconnecting Transmission Owner and System Operator shall not incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days’ written notice to Interconnecting Transmission Owner and System Operator prior to cancellation, termination, or material change of such insurance; provided that to the extent the Interconnection Customer is satisfying the requirements of subpart (d) of this paragraph by means of a presently existing insurance policy, the Interconnection Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Interconnecting Transmission Owner and System Operator as required above.

If the requirement of clause (a) in the paragraph above prevents Interconnection Customer from obtaining the insurance required without added cost or due to written refusal by the insurance carrier, then upon Interconnection Customer’s written notice to Interconnecting Transmission Owner and System Operator, the requirements of clause (a) shall be waived.

8.3 Evidence of Insurance

Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnection Customer.

The Interconnection Customer is responsible for providing the Interconnecting Transmission Owner and the System Operator with evidence of insurance in compliance with this Tariff on an annual basis.

Prior to the Interconnecting Transmission Owner commencing work on Interconnection Facilities, Network Upgrades and Distribution Upgrades, the Interconnection Customer shall have its insurer furnish to the Interconnecting Transmission Owner and the System Operator certificates of insurance evidencing the insurance coverage required above. The Interconnection Customer shall notify and send to the Interconnecting Transmission Owner and the System Operator a certificate of insurance for any policy written on a "claims-made" basis. The Interconnecting Transmission Owner and the System Operator may at their discretion require the Interconnection Customer to maintain tail coverage for three years on all policies written on a "claims-made" basis.

8.4 Self Insurance

If Interconnection Customer is a company with a self-insurance program established in accordance with commercially acceptable risk management practices, Interconnection Customer may comply with the following in lieu of the above requirements as reasonably approved by the Interconnecting Transmission Owner and the System Operator:

- Interconnection Customer shall provide to Interconnecting Transmission Owner and System Operator, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure to a level of coverage equivalent to that required.
- If Interconnection Customer ceases to self-insure to the standards required hereunder, or if Interconnection Customer is unable to provide continuing evidence of Interconnection Customer's financial ability to self-insure, Interconnection Customer agrees to promptly obtain the coverage required under Article 8.1.

8.5 Interconnecting Transmission Owner Insurance

The Interconnecting Transmission Owner agrees to maintain general liability insurance or self-insurance consistent with the Interconnecting Transmission Owner's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Interconnecting Transmission Owner's liabilities undertaken pursuant to this Agreement.

Article 9. Confidentiality

9.1 Confidential Information shall include without limitation, all information governed by the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, and any confidential and/or proprietary information provided by a Party to the another Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party(ies) and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party(ies) as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or

proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

- 9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if the Commission, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this Agreement prior to the release of the Confidential Information to the Commission. The Party shall notify the other Party(ies) to this Agreement when it is notified by the Commission that a request to release Confidential Information has been received by the Commission, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

Article 10. Disputes

- 10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.
- 10.2 In the event of a dispute, a Party shall provide the other Party(ies) with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.
- 10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, any Party may contact the Commission's Dispute Resolution Service (DRS) for assistance in resolving the dispute.
- 10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical

expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.

- 10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for its pro-rata share of any costs paid to neutral third-parties.
- 10.6 If no Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then each Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

- 11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with Commission policy and Internal Revenue Service requirements.
- 11.2 Each Party shall cooperate with the other to maintain the other Party's(ies') tax status. Nothing in this Agreement is intended to adversely affect the Interconnecting Transmission Owner's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by the Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.1 Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, this Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, there are no other agreements,

representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of the New England Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects the System Operator, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected to the New England Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric

reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party(ies), first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party(ies). The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party(ies) copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party(ies) for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

Consistent with Section 4.8 of Schedule 23, the Interconnecting Transmission Owner and the System Operator shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party(ies) and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national carrier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

[To be supplied]

If to the Interconnecting Transmission Owner:

[To be supplied]

If to the System Operator:

ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: 413-540-4203

With a copy to:

Billing Department

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: [To be supplied]

Interconnecting Transmission Owner[To be supplied]

System Operator: ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: 413-540-4203

With a copy to:

Billing Department

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by a Party to the other Party(ies) and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Phone: _____ Fax: _____

E-mail: _____

If to the Interconnecting Transmission Owner:

Phone: _____ Fax: _____

E-mail: _____

If to the System Operator:

Phone: _____ Fax: 413-540-4203

E-mail: geninterconn@iso-ne.com

With a copy to:

Billing Department

Facsimile: (413) 535-4024

E-mail: billingdept@iso-ne.com

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

[To be supplied]

Interconnecting Transmission Owner's Operating Representative:

[To be supplied]

System Operator's Operating Representative:

ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: (413) 540-4203

E-mail: geninterconn@iso-ne.com

DUNS Numbers:

Interconnection Customer: [To be supplied]

Interconnecting Transmission Owner: [To be supplied]

13.5 Changes to the Notice Information

A Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

[Insert name of] (Interconnecting Transmission Owner)

Name: _____

Title: _____

Date: _____

[Insert name of] (Interconnection Customer)

Name: _____

Title: _____

Date: _____

ISO New England Inc. (System Operator)

Name: _____

Title: _____

Date: _____

ATTACHMENTS TO SGIA

- | | |
|--------------|---|
| Attachment 1 | Glossary of Terms |
| Attachment 2 | Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment |
| Attachment 3 | One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment and Upgrades |
| Attachment 4 | Milestones |
| Attachment 5 | Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs |
| Attachment 6 | Interconnecting Transmission Owner's Description of its Upgrades, and Best Estimates of Upgrade Costs |
| Attachment 7 | Commercial Operation Date |

Glossary of Terms

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Standards – The requirements and guidelines of NERC, NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Systems.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (1) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and survey, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard (“CC Interconnection Standard”) – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources and Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource (“CNR”) – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability (“CNR Capability”) – The MW quantity associated with CNR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Capacity Network Resource Group Study (“CNR Group Study”) – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service (“CNR Interconnection Service”) - The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer’s CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Cluster Enabling Transmission Upgrade (“CETU”) shall mean new significant transmission line infrastructure that consists of AC transmission lines and related terminal equipment having a nominal voltage rating at or above 115 kV or HVDC transmission lines and HVDC terminal equipment that is identified through the Clustering Enabling Transmission Upgrade Regional Planning Study conducted to accommodate the Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered. The CETU shall be considered part of a Generator Interconnection Related Upgrade and be categorized as Interconnection Facilities or Network Upgrades.

Cluster Enabling Transmission Upgrade Regional Planning Study (“CRPS”) shall mean a study conducted by the System Operator under Attachment K, Section II of the Tariff to identify the Cluster Enabling Transmission Upgrade and associated system upgrades to enable the interconnection of Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered.

Cluster Interconnection Facilities Study (“CFS”) shall mean an Interconnection Facilities Study performed using Clustering pursuant to Section 1.5.3.4.

Cluster Interconnection System Impact Study (“CSIS”) shall mean an Interconnection System Impact Study performed using Clustering pursuant to Section 1.5.3.3.

Cluster Participation Deposit shall mean the initial and additional deposit due under Sections 1.5.3.3.2.2 and 1.5.3.4.4.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – The date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Attachment 7 to the Standard Small Generator Interconnection Agreement.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner’s facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner’s Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Generating Facility – The Interconnection Customer’s device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking

board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Initial Synchronization Date – The date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date – The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner’s Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner – A Transmission Owner that owns, leases or otherwise possesses an interest in, or a Non-Incumbent Transmission Developer that is not a Participating Transmission Owner that is constructing, a portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Small Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner’s Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Attachment 2 to the Standard Small Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner’s Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer – Any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Small Generating Facility with the Administered Transmission System under the Standard Small Generator Interconnection Procedures.

Interconnection Customer’s Interconnection Facilities shall mean all facilities and equipment, as identified in Attachment 2 of the Standard Small Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification,

addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities – The Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study – A study conducted by the System Operator, Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 3.5 of the Standard Small Generator Interconnection Procedures.

Interconnection Facilities Study Agreement – The form of agreement contained in Attachment 8 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study – A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 3.3 of the Standard Small Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the

Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection Feasibility Study Agreement – The form of agreement contained in Attachment 6 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request – The Interconnection Request (a) shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP; (iv) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (v) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System; or (vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service – The service provided by the System Operator and the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Small Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study – Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Small Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement – Any of the following agreements: the Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement attached to the Standard Small Generator Interconnection Procedures.

Interconnection System Impact Study – An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Small Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and 3.4.

Interconnection System Impact Study Agreement – The form of agreement contained in Attachment 7 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Network Capability Interconnection Standard (“NC Interconnection Standard”)– The minimum criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Network Resource

Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Network Resource (“NR”) – The portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.

Network Resource Capability (“NR Capability”) – The MW quantity associated with NR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Network Resource Interconnection Service (“NR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Generating Facility to the Administered Transmission System in accordance with the Network Capability Interconnection Standard. An Interconnection Customer’s NR Interconnection Service shall be solely for the megawatt amount of the NR Capability. NR Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the New England Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Administered Transmission System to accommodate the interconnection of the Small Generating Facility with the Administered Transmission System. Network Upgrades do not include Distribution Upgrades.

Notice of Dispute – A written notice of a dispute or claim that arises out of or in connection with the Standard Small Generator Interconnection Agreement or its performance.

Operating Requirements – Any operating and technical requirements that may be applicable due to System Operator or the Interconnecting Transmission Owner’s requirements, including those set forth in the Small Generator Interconnection Agreement, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

Party– The System Operator, Interconnecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Administered Transmission System.

Queue Position -- The order of a valid request in the New England Control Area, relative to all other pending requests in the New England Control Area, that is established based upon the date and time of receipt of such request by the System Operator. Requests are comprised of interconnection requests for Generating Facilities, Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. References to a “higher-queued” Interconnection Request shall mean one that has been received by System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as “lower-queued.”

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – A Generating Facility having a maximum gross capability at or above zero degrees F of 20 MW or less.

Stand Alone Network Upgrades – Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Attachment 2 to the Standard Small Generator Interconnection Agreement.

Study Case shall have the meaning specified in Sections 3.3.2 and 3.4.3 of this SGIP.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study.

Tariff – The System Operator’s or Affected System's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation – The period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Upgrades – The required additions and modifications to the Administered Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

**Description and Costs of the Small Generating Facility,
Interconnection Facilities, and Metering Equipment**

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Interconnecting Transmission Owner. The Interconnecting Transmission Owner will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

I. DESCRIPTION OF MAJOR COMPONENTS

A. Small Generating Facility

(1) Description of Small Generating Facility.

[insert]

(2) The Small Generating Facility shall receive:

___ Network Resource Interconnection Service for the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer, and [insert gross and net at or above 0 degrees F] MW for Winter.

___ Capacity Network Resource Interconnection Service for: (a)(i) the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer and [insert gross and net at or above 0 degrees F] MW for Winter; and (ii) the CNR Capability at [insert net] MW for Summer and [insert net] MW for Winter, which shall not exceed [insert the maximum net MW electrical output of the Generating Facility at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter].

- (3) Detailed Description of Small Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	
Manufacturer	
Model	
Designation of Generator(s)	
Excitation System Manufacturer	
Excitation System Model	
Voltage Regulator Manufacturer	
Voltage Regulator Model	
Generator Ratings	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 90 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 50 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 20 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above zero Degrees F	
Station Service Load For Each Unit	
Overexcited Reactive Power at Rated MVA and Rated Power Factor	
Underexcited Reactive Power at Rated MVA and Rated Power Factor	

Generator Short Circuit and Stability Data	
Generator MVA rating	
Generator AC Resistance	
Subtransient Reactance (saturated)	
Subtransient Reactance (unsaturated)	
Transient Reactance (saturated)	
Negative sequence reactance	
Transformer Data	
Number of units	
Self Cooled Rating	
Maximum Rating	
Winding Connection (LV/LV/HV)	
Fixed Taps	
Z1 primary to secondary at self cooled rating	
Z1 primary to tertiary at self cooled rating	
Z1 secondary to tertiary at self cooled rating	
Positive Sequence X/R ratio primary to secondary	
Z0 primary to secondary at self cooled rating	
Z0 primary to tertiary at self cooled rating	
Z0 secondary to tertiary at self cooled rating	
Zero Sequence X/R ratio primary to tertiary	

B. Interconnection Facilities

[insert]

C. Metering Equipment

[insert]

D. Other Components

[insert]

II. INTERCONNECTION EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

A. Point of Change of Ownership; Point of Interconnection

[insert]

B. Description of Responsibilities

[insert]

III. PRICING ESTIMATES

A. Interconnection Facilities

[insert]

B. Metering Equipment

[insert]

C. Operation and Maintenance

[insert]

Attachment 3

**One-line Diagram Depicting the Small Generating Facility, Interconnection
Facilities, Metering Equipment, and Upgrades**

[insert]

Milestones

- 1. Milestones and Other Requirements:** The description and entries listed in the following table establish the required Milestones in accordance with the provisions of the SGIP and this SGIA. The referenced section of the SGIP or article of the SGIA should be reviewed to understand the requirements of each milestone.

Item No.	Milestone Description	Responsible Party	Date	SGIP/SGIA Reference
1	Submit updated data “as purchased”	Interconnection Customer	No later than 180 Calendar Days prior to Initial Synchronization Date	
2	Submit supplemental and/or updated data “as built/as-tested”	Interconnection Customer	Prior to Commercial Operation Date	
3	Provide quarterly written progress reports	Interconnection Customer and Interconnecting Transmission Owner	15 Calendar Days after the end of each quarter beginning the quarter that includes the date for Milestone #3 below and ending when the entire Small Generating	

			Facility and all required Interconnection Facilities and Network Upgrades are in place	
4	Deliver to Transmission Owner “as built” drawings, information and documents regarding Interconnection Customer’s Interconnection Facility	Interconnection Customer	If requested, within 120 Calendar Days after Commercial Operation date	

2. Milestones Applicable If Facilities Study Has Been Waived by Interconnection Customer:

Item No.	Milestone Description	Responsible Party	Date	SGIP/SGIA Reference
1	Siting approval for the Generating Facility and Interconnection Facilities	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(i)
2	Engineering of Interconnection Facilities approved by Interconnecting Transmission Owner	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(ii)

3	Commit to the ordering of long lead time material for Interconnection Facilities and system upgrades	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(iii)
4	In-Service Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	
5	Initial Synchronization Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	SGIP § 3.4.5(iv)
6	Commercial Operation Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	SGIP § 3.4.5(v)

3. Milestones Applicable Solely for CNR Interconnection Service. In addition to the Milestones above, the following Milestones apply to Interconnection Customers requesting CNR Interconnection Service:

Item #	Milestone	Responsible Party	Date	SGIP/SGIA Reference
1	Submit necessary requests for participation in the Forward Capacity Auction associated with the Generating Facility's requested Commercial Operation Date, in accordance with Section III.13 of the Tariff	Interconnection Customer		1.7.1.3(i)

2	Participate in a CNR Group Study	Interconnection Customer; System Operator		1.7.1.3(ii)
3	Qualify and receive a Capacity Supply Obligation in accordance with Section III.13 of the Tariff	Interconnection Customer		1.7.1.3(iii)
4	Complete a re-study of the applicable Interconnection Study to determine the cost responsibility for facilities and upgrades necessary to accommodate the Interconnection Request based on the results of the Forward Capacity Auction, Reconfiguration Auction or bilateral transaction through which the Interconnection Customer received a Capacity Supply Obligation	System Operator		1.7.1.3(iv)

**Additional Operating Requirements for the
New England Transmission System and Affected Systems Needed to Support
the Interconnection Customer's Needs**

The Interconnecting Transmission Owner shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the New England Transmission System.

I. OPERATING REQUIREMENTS

[Insert]

**Interconnecting Transmission Owner's
Description of its Upgrades
and Best Estimate of Upgrade Costs**

The Interconnecting Transmission Owner shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Interconnecting Transmission Owner shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

I. DESCRIPTION OF UPGRADES

A. Distribution Upgrades

[Insert]

B. Network Upgrades

[Insert]

(1) Stand Alone Network Upgrades

(2) Other Network Upgrades

C. Affected System Upgrades

[Insert]

D. Contingency Upgrades

(1) Long Lead Facility-Related Upgrades. The Interconnection Customer's Small Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility

achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

[insert list of upgrades]

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this SGIA in accordance with Article 7, and the System Operator will initiate all necessary steps to terminate this SGIA, in accordance with Article 3.

(2) Other Contingency Upgrades. [*e.g.*, list of upgrades associated with higher queued Interconnection Requests with SGIAs prior to this SGIA and any other contingency upgrades that the Parties may deem necessary for the interconnection of the Small Generating Facility.]

E. Post-Forward Capacity Auction Re-study Upgrade Obligations.

[Insert any changes in upgrade obligations that result from re-study conducted post receiving a Capacity Supply Obligation in accordance with the Tariff.]

Commercial Operation Date

This Attachment 7 is a part of the SGIA between System Operator, Interconnecting Transmission Owner and Interconnection Customer.

[Date]

[Interconnecting Transmission Owner; Address]

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: _____ Small Generating Facility

Dear _____:

On [Date] [Interconnection Customer] has completed Trial Operation of Unit No. ____.
This letter confirms that [Interconnection Customer] commenced commercial operation of Unit No. ____ at the Small Generating Facility, effective as of [Date plus one day].

Thank you.

[Signature]

[Interconnection Customer Representative]

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

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

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

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

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

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area

meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

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

$$LRA_Z = Resources_Z + Proxy Units_Z - (Proxy Units Adjustment_Z(1-FOR_Z)) - (Firm Load Adjustment_Z(1-FOR_Z))$$

In which:

$$LRA_Z = \text{MW of Local Resource Adequacy Requirement for Capacity Zone Z;}$$

$$Resources_Z = \text{MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;}$$

$$Proxy Units_Z = \text{MW of proxy unit additions in Load Zone Z;}$$

$$Firm Load Adjustment_Z = \text{MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and}$$

$$FOR_Z = \text{Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.}$$

$$Proxy Units Adjustment = \text{MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1}$$

days/year.

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

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.
- (d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

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

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{RestofNewEngland} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

- (a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

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

(a) For the relevant Capacity Commitment Period, the network model shall include:

- (i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;
- (ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and
- (iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

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

III.12.6.1. Process for Establishing the Network Model.

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

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

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the

transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

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

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

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

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

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

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

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

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

III.12.6.3. Evaluation Criteria.

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

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

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

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

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

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

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

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

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3 and 4A of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all

other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

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

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,
- (e) [all Existing Distributed Energy Capacity Resources.](#)

but shall exclude:

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

(fg) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(gh) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process. [The rating of Distributed Energy Capacity Resources shall be the existing Qualified Capacity for the Capacity Commitment Period being evaluated.](#)

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

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

For existing Active Demand Capacity Resources:

Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

[For Distributed Energy Capacity Resources:](#)

[For each Distributed Energy Capacity Resource, the availability metric for each underlying technology type will be applied in the same manner as it would be applied if the Distributed Energy Capacity Resource were qualified as a generator or demand response resource.](#)

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

- (a) **Implement voltage reduction.** The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).
- (b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.
- (c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission

constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the

import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, “at criterion” system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC’s assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

- A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

- (i) The transmission system will be modeled using the following conditions:

1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
 2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
 4. [Qualified Existing Distributed Energy Capacity Resources reflecting their existing Qualified Capacity for the Capacity Commitment Period;](#)
 45. Transfers on the transmission system that impact the transfer capability of the interconnection under study.
- (ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.
- (iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. Adding Proxy Units within New England when the New England system is short of capacity. In modeling New England as part of the interconnected system, if New England is

short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.

- B. Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.
- C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

- D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.
- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system

isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.

- C. Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections

shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.
- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).
- C.** The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- D.** The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- E.** For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity

Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

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

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), ~~or~~ a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4) or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, ~~and~~ New Demand Capacity Resource, and New Distributed Energy Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit. The Lead Market Participant for a resource participating in a Forward Capacity Auction may not change in the 15 Business Days prior to, or during, that Forward Capacity Auction.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), ~~or~~ a New Demand Capacity Resource or Existing Demand Capacity Resource (as ~~defined discussed~~ in Section III.13.1.4), or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (as defined in Section III.13.1.4A) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New ~~Capacity~~-Generating Capacity Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A Market Participant that elects to have a resource that has previously been counted as a capacity resource participate in the Forward Capacity Auction as a New Generating Capacity Resource, must notify the ISO when the existing resource ceases to operate and the New Generating Capacity Resource commences operation. If a Market Participant with a resource that has previously been counted as a capacity resource elects, pursuant to Section III.13.3.4(a)(iii), to have the resource that has previously been counted as a capacity resource cover the Capacity Supply Obligation of a New Generating Capacity

Resource and the resource that has previously been counted as a capacity resource must take an outage in order for the New Generating Capacity Resource to commence Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff), then the Market Participant must notify the ISO that the outage is for the purpose of the New Generating Capacity Resource commencing Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of

Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation.

(c) A Project Sponsor or Lead Market Participant making an election pursuant to this Section III.13.1.1.1.3 must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.3.A. Treatment of New Incremental Capacity and Existing Generating Capacity at the Same Generating Resource.

For incremental summer capacity seeking to participate in the Forward Capacity Auction pursuant to Section III.13.1.1.1.3 or incremental winter capacity that meets the investment thresholds in Section III.13.1.1.1.3 as applied to the resource's winter Qualified Capacity, if the incremental summer or winter capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental summer or winter capacity with excess existing winter or summer Qualified Capacity at that same

resource, as appropriate, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.3 or Section III.13.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Retirement Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every Asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the New England state in which it is geographically located. A resource physically located in United States federal waters directly adjacent to New England state maritime boundaries and directly

interconnecting to the New England system is considered to be geographically located in the state where its Point of Interconnection is located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Capacity Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also have, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, a valid Interconnection Request under Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the FCM Deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement

Deposit described in Section III.13.1.9.3. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff); the project address or location, and if relevant, asset identification number; the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; a general

description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period pursuant to Section III.13.1.1.2.2.1.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated

with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(c) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (c) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent

operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) and/or the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a Rationing Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export 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 pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New

Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the

summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will (i) include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) and (ii) exclude any existing capacity that will be retired as of the start of the same Capacity Commitment Period. Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New

Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer, as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources

with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

- (a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;
- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Resource; (ii) for the notification to a Conditional Qualified New Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Resource, the Queue Position of the Conditional Qualified New Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant may not elect Renewable Technology Resource treatment for the FCA associated with a Capacity Commitment Period beginning on or after June 1, 2025.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Capacity Resource shall submit a Renewable Technology Resource election form no later than two Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.1.1.6. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.1.1.2.7 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

- (a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c), (d) and (e) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than five Business Days after the deadline for submitting Renewable Technology Resource elections.
- (b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.
- (c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.
- (d) The cap for each Capacity Commitment Period beginning on June 1, 2020 or June 1, 2021 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.
- (e) The cap for each Capacity Commitment Period beginning on June 1, 2022 or June 1, 2023 or June 1, 2024 is 514 MW minus the cumulative amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources in the first or second run of the primary auction-clearing process pursuant to Section III.13.2 for each Capacity Commitment Period that begins on or after June 1, 2021.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), ~~or~~ as a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4), [or as a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource \(Section III.13.1.4A\)](#) shall be an Existing Generating Capacity Resource.

III.13.1.2.1.1. Attributes of Existing Generating Capacity Resources.

For purposes of Forward Capacity Auction qualification, a Market Participant may not change any Existing Generating Capacity Resource attribute (including but not limited to the resource's status as an Intermittent Power Resource) in the period beginning 20 Business Days prior to the Existing Capacity Retirement Deadline and ending with the conclusion of the Forward Capacity Auction. Outside of this period, any such change must be accompanied by documentation justifying the change.

III.13.1.2.1.2 Rationing Minimum Limit.

No later than 120 days before the Forward Capacity Auction Market Participants may specify a Rationing Minimum Limit for an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating

Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources.

The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Summer Intermittent Reliability Hours. If there are less than five full summer periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Winter Intermittent Reliability Hours. If there are less than five full winter periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) is associated with a New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) achieves FCM Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings [or Existing Distributed Energy Capacity Resource's positive summer Seasonal DECR Audit Values](#) from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1 [or Section III.13.1.4A.2.A](#)] plus [the amount of the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#)'s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) achieves FCM Commercial Operation, the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#)'s summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1 [or Section III.13.1.4A.2.A.1.1](#), except that no data from the time period prior to the New Generating Capacity Resource [or New Distributed Energy Capacity](#)

[Resource](#)'s FCM Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#).

(b) Where an Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) is associated with a New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) achieves FCM Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings [or Existing Distributed Energy Capacity Resource's positive winter Seasonal DECR Audit Values](#) from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2 [or Section III.13.1.4A.2.A.1.2](#)] plus [the amount of the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#)'s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#) achieves FCM Commercial Operation, the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#)'s winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2 [or Section III.13.1.4A.2.A.1.2](#), except that no data from the time period prior to the New Generating Capacity Resource [or New Distributed Energy Capacity Resource](#)'s FCM Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#).

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Where the most recent summer Seasonal Claimed Capability [or most recent summer Seasonal DECR Audit Value](#), as of the fifth Business Day in October, of an Existing Generating Capacity Resource (other than a Settlement Only Resource or an Intermittent Power Resource) [and Existing Distributed Energy Capacity Resource \(other than one comprised of Settlement Only Resources or an Intermittent Power Resource\)](#) is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1 [and Section III.13.1.4A.2.A.1.1, respectively](#), by:

- (1) for Capacity Commitment Periods beginning prior to June 1, 2023, more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW;
- (2) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:
 - (i) the greater of 10 percent of that summer Qualified Capacity or two MW, or;
 - (ii) 10 MW;

then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#)'s summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability [or summer Seasonal DECR Audit Value](#) as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, [Section III.13.1.4A.1.1.2.3](#), or [Section III.13.1.4A.1.1.2.4](#), modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.13.1.2.2.1.1 [or Section III.13.1.4A.2.A.1.1](#) by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#)'s summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 [or Section III.13.1.4A.2.A.1.1](#) for the Forward Capacity Auction. For an Existing Generating Capacity Resource [or Existing Distributed Energy Capacity Resource](#) subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource (other than a Settlement Only Resource) meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead

Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.2.2.5.1. **[Reserved.]**

III.13.1.2.2.5.2. **Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource, [Existing Distributed Energy Capacity Resource](#), or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.**

Where an Existing Generating Capacity Resource, Existing Demand Capacity Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

[Where an Existing Distributed Energy Capacity Resource \(other than an Intermittent Power Resource\) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.4A.2.A, then that resource must have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.](#)

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

- (a) For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located.
- (b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource as described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.
- (c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in

Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. 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 any type of de-list or export 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. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of 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.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

For the fifteenth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2024), the Dynamic De-List Bid Threshold is \$4.30/kW-month. For each Forward Capacity Auction thereafter, the Dynamic De-List Bid Threshold shall be calculated as described below in this Section III.13.1.2.3.1.A, and shall be published to the ISO's website no later than 5 Business Days before the Existing Capacity Retirement Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) below, a preliminary value of the Dynamic De-List Bid Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-

of-Pool Capacity Zone from the immediately preceding Forward Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.13.2.5.2.1(d), the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Forward Capacity Auction intersects the estimated System-Wide Capacity Demand Curve for the upcoming Forward Capacity Auction. For this purpose, the estimated System-Wide Capacity Demand Curve shall be constructed, in the same manner as described in Section III.13.2.2.1, using the system-wide Marginal Reliability Impact values from the immediately preceding Forward Capacity Auction, the most recent estimate of the Installed Capacity Requirement (net of HQICCs) for the upcoming Forward Capacity Auction, and the Net CONE and Forward Capacity Auction Starting Price for the upcoming Forward Capacity Auction.

(b) The preliminary value of the Dynamic De-List Bid Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction. The preliminary value of the Dynamic De-List Bid Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$Margin = \$1/kW\text{-month} \times \left[\frac{(75\% \times Net\ CONE_{upcoming\ FCA}) - DDBT_{preliminary}}{(75\% \times Net\ CONE_{upcoming\ FCA})} \right]$$

(d) The final value of the Dynamic De-List Bid Threshold for the upcoming Forward Capacity Auction shall be equal to the preliminary value of the Dynamic De-List Bid Threshold calculated pursuant to Sections III.13.1.2.3.1.A(a) and III.13.1.2.3.1.A(b) plus the margin value calculated pursuant to Section III.13.1.2.3.1.A(c).

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction qualification process. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the

resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs). The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

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 Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. [Reserved.]

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area, other than an Intermittent Power Resource or a Renewable Technology Resource, seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction qualification process. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the

interface over which the capacity will be exported. Export Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction qualification process. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.5.2.4.

III.13.1.2.3.1.5. Permanent De-List Bids and Retirement De-List Bids.

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids and Retirement De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

III.13.1.2.3.1.5.1. Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-accepted Permanent De-List Bids and Internal Market Monitor-accepted Retirement De-List Bids that are at or above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee during the month of August following the issuance of retirement determination notifications pursuant to Section III.13.1.2.4(a). The Lead Market Participant shall be notified as soon as

practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than the fifth Business Day in the month of September following the review of system needs with the Reliability Committee per (b) above, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

(ii) For a Permanent De-List Bid at or above the Forward Capacity Auction Starting Price for which a Lead Market Participant has not elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

III.13.1.2.3.1.6. Static De-List Bids, Permanent De-List Bids and Retirement De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, Permanent De-List Bid and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-determined or Internal Market Monitor-accepted price for the bid as described in Section III.13.1.2.3.2.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and Export Bids, Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid and each Export Bid at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Capacity

Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid at or above the Dynamic De-List Bid Threshold if the sum of all such bids at or above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor 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).

Sufficient documentation and information about each bid component must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information

on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Static De-List Bids and Export Bids.

The Internal Market Monitor shall review Static De-List Bids and Export Bids and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Static De-List Bid or an Internal Market Monitor-accepted Export Bid. The Internal Market Monitor-accepted Static De-List Bid and Internal Market Monitor-accepted Export Bid shall be equal to the Static De-List Bid or Export Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Static De-List Bid or Internal Market-Monitor-accepted Export Bid that is consistent with the sum of the

resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs.

If an Internal Market Monitor-determined price is established for a Static De-List Bid or an Export Bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(c) shall include an explanation of the Internal Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.

The Internal Market Monitor shall review those Permanent De-List Bids and Retirement De-List Bids identified in Section III.13.1.2.3.2.1 and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Permanent De-List Bid or an Internal Market Monitor-accepted Retirement De-List Bid. The Internal Market Monitor-accepted Permanent De-List Bid and Internal Market Monitor-accepted Retirement De-List Bid shall be equal to the Permanent De-List Bid or Retirement De-List Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Permanent De-List Bid or Internal Market-Monitor-accepted Retirement De-List Bid that is 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 retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-accepted price and the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula.

Net Going Forward Costs =

$$\frac{(GFC - IMR) \times InfIndex}{(CQ_{Summer, kW}) \times (12 \text{ months})}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period.

$CQ_{Summer, kW}$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all

submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00.

$\text{InfIndex} = \text{inflation index. } \text{infIndex} = (1 + i)^4$

Where: "i" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values.

The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and 12 months.

The Existing Capacity Resource's net annual expected cash flow for the first Capacity Commitment Period of the resource's remaining economic life is the resource's expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative. However, effective April 9, 2020, beginning with the sixteenth Forward Capacity Auction, the economic life is the evaluation period in which a resource's net present value is maximized.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid, Permanent De-List Bid, or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2.A may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Capacity Resource submitting a Static De-List Bid or an Export Bid, Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to

ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all Static De-List Bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource’s annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource’s annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (\text{I} + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity; Right to Increase Retirement De-List Bid or Permanent De-List Bid up to IMM-determined substitution auction test price.

(a) No later than five Business Days before the Existing Capacity Qualification Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid, Retirement De-List Bid and substitution auction test price concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2 and Section III.13.2.8.3.1A. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5. For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, within five Business Days of the issuance of the retirement determination notification, a Lead Market Participant that submitted a Retirement De-List Bid or a Permanent De-List Bid and a substitution auction demand bid for the resource associated with the de-list bid, may make the following adjustments:

- (i) for a Retirement De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Retirement De-List Bid, the Internal Market Monitor would have calculated a Retirement De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Retirement De-List Bid price that the Internal Market Monitor would have calculated;
- (ii) for a Permanent De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Permanent De-List Bid, the Internal Market Monitor would have calculated a Permanent De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Permanent De-List Bid price that the Internal Market Monitor would have calculated.

(b) No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than five Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external demand resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long

Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Retirement Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3.A(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3.A(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

- (a) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

- (b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

- (c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3A for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3A, no later than 10 Business Days prior to the Existing Capacity Retirement Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3A.

Contract Description

MW

Contract End Date

NYPA: NY — NE: CMEEC	13.2	8/31/2025
NYPA: NY — NE: MMWEC	53.3	8/31/2025
NYPA: NY — NE: Pascoag	2.3	8/31/2025
NYPA: NY— NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate — NE	Up to 225	10/31/2016
VJO: Highgate — NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II — NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.

Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification

Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

(a) For each New Import Capacity Resource, the Project Sponsor submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the contract period including the entire Capacity Commitment Period, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services

Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

(b) To qualify for Capacity Commitment Periods prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which the import capacity is qualifying, the Project Sponsor must submit documentation of one or more one-year contracts for each prior Capacity Commitment Period, entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract(s); the Project Sponsor must also satisfy the relevant requirements of Sections III.13.1.3.5.1(a) , III.13.1.3.5.2, III.13.1.9, and III.13.3.1.1.

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource for the length of the multi-year contract.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford

the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Project Sponsor entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Capacity Resources.

To participate in a Forward Capacity Auction as a Demand Capacity Resource, a resource must meet the requirements of this Section III.13.1.4. Each Demand Capacity Resource shall be a minimum of 100 kW. An Active Demand Capacity Resource comprises one or more Demand Response Resources located in a single Dispatch Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource comprises one or more Assets located in a single Load Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource may consist of Load Management measures, Distributed Generation measures, or a combination thereof, or may consist solely of Energy Efficiency measures. A Demand Capacity Resource may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit import or export bids or Administrative Export De-List Bids.

III.13.1.4.1. Definition of New Demand Capacity Resource.

A New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, and On-Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. A Demand Capacity Resource that has previously been defined as an Existing Demand Capacity Resource shall be considered a New Demand Capacity Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.1. Qualification Process for New Demand Capacity Resources.

For Forward Capacity Auctions a New Demand Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated demand reduction value as

submitted and reviewed pursuant to this Section III.13.1.4. The FCA Qualified Capacity for a New Demand Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

(a) For a resource to qualify as a New Demand Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated demand reduction values and supporting information in the New Demand Capacity Resource Show of Interest Form as described in Section III.13.1.4.1.1.1. Second, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package as described in Section III.13.1.4.1.1.2.

(b) For a resource to qualify as a New Demand Capacity Resource that is an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Project Sponsor must in addition submit, as part of the New Demand Capacity Resource Qualification Package, a Measurement and Verification Plan providing the documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.1, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.1. New Demand Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit to the ISO a New Demand Capacity Resource Show of Interest Form as described in this Section III.13.1.4.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. A New Demand Capacity Resource Show of Interest Form for a resource composed of Energy Efficiency measures must represent a resource with a new and unique resource identification number. The ISO may waive the submission of any information not required for evaluation of a project.

A completed New Demand Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Capacity Resource will be located; the Dispatch Zone within which an Active Demand Capacity Resource will be located; estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); estimated total summer and winter demand reduction value of the Demand Capacity Resource (for an Active Demand Capacity Resource, this estimate must be

consistent with the baseline calculation methodology in Section III.8.2); supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values; Demand Capacity Resource type (Active Demand Capacity Resource, On-Peak Demand Resource, or Seasonal Peak Demand Resource); brief Demand Capacity Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value; ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; for individual Distributed Generation projects and Demand Capacity Resource projects from a single facility with a demand reduction value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.1.1.2. New Demand Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Capacity Resource Qualification Package shall conform to the requirements of this Section

III.13.1.4.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Demand Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4.1.1.2.2. Measurement and Verification Plan.

For On-Peak Demand Resources and Seasonal Peak Demand Resources, the Project Sponsor must provide in the New Demand Capacity Resource Qualification Package a Measurement and Verification

Plan that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.2.3. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Demand Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Demand Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's Net Supply Capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

III.13.1.4.1.1.2.4. Critical Path Schedule for a Demand Capacity Resource with a Demand Reduction Value of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Demand Capacity Resource with a demand reduction value of at least 5 MW at a single Retail Delivery Point shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.1.1.2.5. Critical Path Schedule for a Demand Capacity Resource with All Retail Delivery Points Having a Demand Reduction Value of Less Than 5 MW.

The Project Sponsor of a Demand Capacity Resource with all Retail Delivery Points having a demand reduction value of less than 5 MW shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project

Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value must be complete.

III.13.1.4.1.1.2.6. [Reserved.]

III.13.1.4.1.1.2.7. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.4.1.1.2.7 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Demand Capacity Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Capacity Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Demand Capacity Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Capacity Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Capacity Resource offer clears. If the Project Sponsor elects 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, then the Project Sponsor may not change the Demand Capacity Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Capacity Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export 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 pursuant to this Section III.13.1.4.1.1.2.7.

III.13.1.4.1.1.2.8. Offer Information From New Demand Capacity Resources.

(a) All New Demand Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Capacity Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

(b) The Project Sponsor for a New Demand Capacity Resource must indicate in the New Demand Capacity Resource Qualification Package if an offer from the New Demand Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.1.1.3. Initial Analysis for Active Demand Capacity Resources.

For each New Demand Capacity Resource that is an Active Demand Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Demand Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.1.4. Consistency of the New Demand Capacity Resource Qualification Package and New Demand Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Capacity Resource Qualification Package for consistency with its New Demand Capacity Resource Show of Interest Form. The New Demand Capacity Resource Qualification Package may not contain material changes relative to the New Demand Capacity Resource Show of Interest Form. A material change may include, but is not limited to the

following: (i) a change in the designation of the Demand Capacity Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Active Demand Capacity Resource is located; (iv) a change in the total summer or winter demand reduction value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); or (vi) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.1.1.5. Evaluation of New Demand Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Demand Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by New Demand Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Capacity Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Capacity Resource are satisfied; and
- (e) whether, in the case of a New Demand Capacity Resource that is an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.6. Qualification Determination Notification for New Demand Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Capacity Resource indicating whether the New Demand Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Capacity Resource type and the Demand Capacity Resource's summer and winter Qualified Capacity, which shall be the ISO-determined summer and winter demand reduction value increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Demand Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.2. Definition of Existing Demand Capacity Resources.

Demand Capacity Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Capacity Resources, shall be Existing Demand Capacity Resources. Existing Demand Capacity Resources shall include and are limited to Demand Capacity Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in this Section III.13.1.4, Existing Demand Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Capacity Resources shall be subject to Section III.13.1.2.2.5.2. An On-Peak Demand Resource or Seasonal Peak Demand Resource may not include in its summer or winter demand reduction value an Energy Efficiency measure whose Measure Life will expire before the beginning of the applicable season of the associated Capacity Commitment Period.

III.13.1.4.2.A Qualified Capacity for Existing Demand Capacity Resources.

(a) For Existing Demand Capacity Resources composed of Energy Efficiency measures,

the summer (or winter, as applicable) Qualified Capacity shall equal the lesser of: (i) the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Existing Capacity Qualification Deadline (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer (or winter, as applicable) capacity that has cleared in a Forward Capacity Auction and has not yet achieved FCM Commercial Operation (provided that such capacity is being monitored by the ISO pursuant to the provisions of Section III.13.3, is expected to achieve all its critical path schedule milestones prior to the start of the applicable season of the relevant Capacity Commitment Period, and for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy) and (ii) the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Demand Capacity Resource.

(b) For Existing Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the summer and winter demand reduction value, respectively, increased by average avoided peak transmission and distribution losses.

III.13.1.4.2.1. Qualified Capacity Notification for Existing Demand Capacity Resources.

(a) For each Existing Demand Capacity Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Retirement Deadline of: the Demand Capacity Resource type; summer and winter Qualified Capacity; the Load Zone in which the Demand Capacity Resource is located; and, for Active Demand Capacity Resources, the Dispatch Zone in which the resource is located.

(b) If the Lead Market Participant believes that the ISO's assessment of the Qualified Capacity is inaccurate, the Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) If a Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource wishes to change its Demand Capacity Resource type, the Market Participant must submit an Updated Measurement and Verification Plan to reflect the change in its resource type. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after

receipt of the Qualified Capacity notification. Designation of the Demand Capacity Resource type may not be changed during the Capacity Commitment Period.

(d) A Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource may provide an Updated Measurement and Verification Plan as described in Section III.13.1.4.3.1.2 that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after receipt of the Qualified Capacity notification.

(e) If an Existing Demand Capacity Resource is not submitting a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification.

III.13.1.4.2.2. Existing Demand Capacity Resource De-List Bids.

An Existing Demand Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Assets associated with Existing Demand Capacity Resources as New Demand Capacity Resources.

III.13.1.4.3. Measurement and Verification Applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

To demonstrate the demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Project Sponsor or Market Participant of such a resource participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals, or reconfiguration auctions shall submit to the ISO the Measurement and Verification Documents in accordance with this Section III.13.1.4.3 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents.

Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Resource or Seasonal Peak Demand Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall serve as the basis for the claimed demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall contain a projection of the On-Peak Demand Resource's or Seasonal Peak Demand Resource's demand reduction value for each month of the Capacity Commitment Period and over the expected Measure Lives associated with the Demand Capacity Resources. An On-Peak Demand Resource's or Seasonal Peak Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Resource or Seasonal Peak Demand Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Project Sponsor's total demand reduction value from eligible pre-existing measures and new measures, and the Project Sponsor's total demand reduction value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO

New England Manuals, and shall be the basis for monthly settlement with Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Project Sponsor, the Measurement and Verification Documents for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Project Sponsor, an Updated Measurement and Verification Plan for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Capacity Resource project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total claimed demand reduction value or the Demand Capacity Resource type from the applicable Forward Capacity Auction in which the Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Capacity Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Project Sponsors for On-Peak Demand Resources and Seasonal Peak Demand Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction value and measures installed by Load Zone and meter domain. Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor or Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4A. Distributed Energy Capacity Resources.

To participate in a Forward Capacity Auction as a Distributed Energy Capacity Resource, a resource must meet the requirements of this Section III.13.1.4A. Each Distributed Energy Capacity Resource shall be a minimum of 100 kW. A facility connected at a point of interconnection that is 5 MW or greater cannot be a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of On-Peak Demand Resource or Seasonal Peak Demand Resource with measures other than Energy Efficiency may not participate in a Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit import or export bids or Administrative Export De-List Bids.

III.13.1.4A.1. Definition of New Distributed Energy Capacity Resources.

A New Distributed Energy Capacity Resource is a Distributed Energy Capacity Resource that has not cleared in a previous Forward Capacity Auction.

III.13.1.4A.1.1. Qualification Process for New Distributed Energy Capacity Resources.

For Forward Capacity Auctions a New Distributed Energy Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated net injection capability and, as applicable, the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4A. The FCA Qualified Capacity for a New Distributed Energy Capacity Resource (other than an Intermittent Power Resource) shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity.

For a resource to qualify as a New Distributed Energy Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated net energy injection values and, as applicable, estimated demand reduction values and supporting information in the New Distributed Energy Capacity Resource Show of Interest Form as described in Section III.13.1.4A.1.1.1. Second, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package as described in Section III.13.1.4A.1.1.2.

III.13.1.4A.1.1.1. New Distributed Energy Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit to the ISO a New Distributed Energy Capacity Resource Show of Interest Form as described in this Section III.13.1.4A.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project.

(a) General Requirements. A completed New Distributed Energy Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; the DRR Aggregation Zone, Load Zone and Dispatch Zone within which the resource will be located; a description of the project and its expected configuration, including the types of generation and demand response comprising the project; a description of the customer classes and end-uses served by the project; the resource's expected Commercial Operation date; estimated summer and winter net injection capability values (MW) per facility; the installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; ISO Market Participant status and ISO customer identification (if applicable); Project Sponsor's contact information and the ISO Customer Status; expected nameplate capacity by technology type per facility; indication of whether the project elects Intermittent Power Resource treatment (available if the project is a homogenous aggregation of intermittent technology); and the project's applicable technical and financial contacts.

For purposes of this Section III.13.1.4A:

(i) If a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection.

(ii) If a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource. If the resource includes Demand Response Resources, the completed New Distributed Energy Capacity Resource Show of Interest Form shall include the following additional information: the estimated summer and winter demand reductions values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section III.8.2); and supporting documentation (e.g.,

engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point , then the completed New Distributed Energy Capacity Resource Show of Interest Form for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant’s portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater or Equal to 1 MW and less than 5 MW. If the resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed New Distributed Energy Capacity Resource Show of Interest Form for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

III.13.1.4A.1.1.2. New Distributed Energy Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Distributed Energy Capacity Resource Qualification Package shall conform to the requirements of this Section III.13.1.4A.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4A.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Distributed Energy Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public

benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4A.1.1.2.2. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Distributed Energy Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Distributed Energy Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's net injection capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

(c) The requirements of this Section III.13.1.4A.1.1.2.2 shall not apply for facilities with a net injection capability equal to or greater than 1 MW and less than 5 MW at a point of interconnection.

III.13.1.4A.1.1.2.3. Critical Path Schedule for a Distributed Energy Capacity Resource Having a Facility with a Demand Reduction Value or Net Injection Capability of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Distributed Energy Capacity Resource with a customer facility having a demand reduction value of at least 5 MW at a single Retail Delivery Point or having behind-the-meter generation with net injection capability greater than 5 MW at a single Retail Delivery Point, shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4A.1.1.2.4. Critical Path Schedule for a Distributed Energy Capacity Resource with All Facilities Having a Demand Reduction Value or Net Injection Capability of Less Than 5 MW at a Single Retail Delivery Point or Point of Interconnection.

The Project Sponsor of a Distributed Energy Capacity Resource with all facilities having a demand reduction value or net injection capability of less than 5 MW at a single Retail Delivery Point or point of interconnection shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value and net injection capability achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value and net injection capability must be complete.

III.13.1.4A.1.1.2.5. Additional Requirements for Distributed Energy Capacity Resources that are Intermittent Power Resources

In addition to the information described elsewhere in this Section III.13.1.4A.1.1.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III. 13.1.4A.1.1.2 (b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.4A.1.1.2.6. Offer Information From New Distributed Energy Capacity Resources.

The Project Sponsor for a New Distributed Energy Capacity Resource must indicate in the New Distributed Energy Capacity Resource Qualification Package if an offer from the New Distributed Energy Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4A.1.1.3. Initial Analysis for Distributed Energy Capacity Resources.

For each New Distributed Energy Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Distributed Energy Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Distributed Energy Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Distributed Energy Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4A.1.1.4. Consistency of the New Distributed Energy Capacity Resource Qualification Package and New Distributed Energy Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package for consistency with its New Distributed Energy Capacity Resource Show of Interest Form. The New Distributed Energy Capacity Resource Qualification Package may not contain material changes relative to the New Distributed Energy Capacity Resource Show of Interest Form. If a material change exists between the New Distributed Energy Capacity Resource Qualification Package and the New Distributed Energy Capacity Resource Show of Interest Form, the New Distributed Energy Capacity Resource Show of Interest Form will be withdrawn by the ISO. A material change includes, but is not limited to the following: (i) a misrepresentation or change of the interconnection status of a facility within the New Distributed Energy Capacity Resource; (ii) the addition of facilities at a point of interconnection with net injection capability greater than 1 MW; (ii) a change in the Project Sponsor, subject to review by

the ISO of the capability and experience of the new Project Sponsor; (iii) a change in DRR Aggregation Zone within which the project is located; (iv) for any component of the New Distributed Energy Capacity Resource that is a Demand Response Resource, an aggregate change in the total summer or winter demand reduction values of all such Demand Response Resources by more than 30 percent; (v) for any component of the New Distributed Energy Capacity Resource with net injection capability less than 5 MW, a change in the total summer or winter net injection capability of the resource by more than 30 percent; (vi) for non-demand response components of a New Distributed Energy Capacity Resource, the introduction of a new technology type for the New Distributed Energy Capacity Resource; (vii) for demand response components of a the New Distributed Energy Capacity Resource, a change to the technology type providing demand reduction for the New Distributed Energy Capacity Resource; (viii) for a facility that interconnects at a point of interconnection, any increase in size of the facility; (ix) for any non-demand response components of any New Distributed Energy Capacity Resource that interconnects at a point of interconnection, a decrease in size greater than 60 percent for any facility with greater than 1 MW connected at the same point of interconnection.

III.13.1.4A.1.1.5. Evaluation of New Distributed Energy Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Distributed Energy Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4A and whether, based on the information provided, the Distributed Energy Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by New Distributed Energy Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4A;
- (b) whether the critical path schedule submitted by New Distributed Energy Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Distributed Energy Capacity Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Distributed Energy Capacity Resource are satisfied; and

(e) whether the customer acquisition plan and source of funding plan are sufficiently detailed and reasonably achievable.

III.13.1.4A.1.1.6. New Distributed Energy Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Distributed Energy Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.4A.2.A.1, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity.

III.13.1.4A.1.1.7. Qualification Determination Notification for New Distributed Energy Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Distributed Energy Capacity Resource indicating whether the New Distributed Energy Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Distributed Energy Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Distributed Energy Capacity Resource's summer and winter Qualified Capacity, which shall be, which shall be the ISO-determined summer and winter net injection capability and demand reduction value, which in the latter case shall be increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Distributed Energy Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4A.2. Definition of Existing Distributed Energy Capacity Resources.

Existing Distributed Energy Capacity Resources shall include Distributed Energy Capacity Resources that have cleared in a previous Forward Capacity Auction. Except as specified in this Section III.13.1.4A, Existing Distributed Energy Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Distributed Energy Capacity Resources shall be subject to Section III.13.1.2.2.5.2. Any Distributed Energy Resource Aggregation that is part of an Existing Capacity Resource shall count only as existing Qualified Capacity, and shall not count toward the Qualified Capacity of a New Distributed Energy Capacity Resource. Any Existing Generating Capacity Resource or Existing Demand Capacity Resource that could qualify as an Existing Distributed Energy Capacity Resource may convert to an Existing Distributed Energy Capacity Resource.

III.13.1.4A.2.A Qualified Capacity for Existing Distributed Energy Capacity Resources.

III.13.1.4A.2.A.1 Existing Distributed Energy Capacity Resources Other Than Intermittent Power Resources

III.13.1.4A.2.A.1.1 Summer Qualified Capacity

The summer Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer Seasonal Audit Value from the five most recent years, as of the fifth Business Day in October of each year, with only positive summer value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five summer Seasonal Audit Values, then the summer Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous summer Seasonal Audit Values, as of the fifth Business Day in October of each year, with only positive summer values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.1.2 Winter Qualified Capacity

The winter Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's winter Seasonal Audit Value from the five most recent years, as of the fifth Business Day in June of each year, with only positive winter

value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five winter Seasonal Audit Values, then the winter Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous winter Seasonal Audit Values, as of the fifth Business Day in June of each year, with only positive winter values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.2 Existing Distributed Energy Capacity Resources That Are Intermittent Power Resources

Existing Distributed Energy Capacity Resources that are Intermittent Power Resources shall follow the same rules for Existing Generating Capacity Resources that are Intermittent Power Resources in section III.13.1.2.2.2. The Existing Qualified Capacity may not be greater than the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Distributed Energy Capacity Resource.

III.13.1.4A.2.A.3 Qualified Capacity Adjustment for Partially New and Partially Existing Resources

Rules related to a Distributed Energy Capacity Resource's Qualified Capacity Adjustment for Partially New and Partially Existing Resources can be found in Section III.13.1.2.2.3.

III.13.1.4A.2.A.4 Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Rules related to a Distributed Energy Capacity Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline can be found in Section III.13.1.2.2.4.

III.13.1.4A.2.1. Qualified Capacity Notification for Existing Distributed Energy Capacity Resources.

(a) For each Existing Distributed Energy Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of

the resource's summer Qualified Capacity and winter Qualified Capacity and the DRR Aggregation Zone in which the Existing Distributed Energy Capacity Resource is located.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Distributed Energy Capacity Resource, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Distributed Energy Capacity Resource does not submit a Static De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.4A.2.2. Existing Distributed Energy Capacity Resource De-List Bids.

An Existing Distributed Energy Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Distributed Energy Resource Aggregations associated with Existing Distributed Energy Capacity Resources as New Distributed Energy Capacity Resources.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.4.1.1.6. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Capacity Resource, April through November where the summer resource is a Demand Capacity

Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Capacity Resource, December through March where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (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 its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Capacity Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Offers composed of separate resources are subject to the locational restrictions specified in the following table:

	Location of Summer Resource
--	------------------------------------

		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)
	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

(e) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource of the resource’s final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource’s financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource, ~~or~~ an Existing Generating Capacity Resource, [a New Distributed Energy Capacity Resource, or an Existing Distributed Energy Capacity Resource](#) as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the

Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. [A New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied FCA Resource.](#) All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource, ~~or~~ Existing Import Capacity Resource, [New Distributed Energy Capacity Resource, or Existing Distributed Energy Capacity Resource](#) and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capacity if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Capacity Resource; and (ii) 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 the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list, retire or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids.

(f) The name of each Lead Market Participant submitting Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b), and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids, Permanent De-List Bids, and Retirement De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

(g) No later than five Business Days after the close of the New Capacity Show of Interest Submission Window, the ISO shall post on its website the aggregate quantity of supply offers and demand bids that have been elected to participate in the substitution auction by Capacity Zone (where the zones used are those being studied for inclusion in the associated Forward Capacity Auction pursuant to Section III.12.4).

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Capacity Resources shall be required to meet

the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Capacity Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Capacity Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Capacity Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, the financial assurance required prior to the auction pursuant to FAP will be released pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Capacity Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Capacity Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4A, it shall lose its Capacity Supply Obligation and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Capacity Resource achieves FCM Commercial Operation, its financial assurance obligation shall be released pursuant to the terms of the

ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource or the Elective Transmission Upgrade achieves FCM Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Capacity Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such

deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Capacity Resources \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff	New Generating Capacity Resources $<$ 20 MW and \geq 2 MW	Imports and New Demand Capacity Resources		New Generating Capacity Resources $<$ 2 MW
<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>	<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6,500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for FCM Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the

affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;
- (b) the Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the New Capacity Show of Interest Submission Window will be in April, approximately four years and two months before the beginning of the Capacity Commitment Period;
- (d) the Existing Capacity Qualification Deadline will be 90 days after the Existing Capacity Retirement Deadline, approximately four years before the beginning of the Capacity Commitment Period;
- (e) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (f) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity Auction prior to the ninth Forward Capacity Auction (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 its New

Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

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, and New Distributed Energy 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, [or New Distributed Energy 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, [or New Distributed Energy 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, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be q_1, q_2, \dots, 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \dots & \dots, \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

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 and Existing Distributed Energy 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, [and Existing Distributed Energy Capacity Resources](#) 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, [or Existing Distributed Energy 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.

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, and New Distributed Energy 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, and Existing Distributed Energy 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, [or Existing Distributed Energy 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 reliability 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.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), ~~or~~ a New Demand Capacity Resource (pursuant to Section III.13.1.4), [or Distributed Energy Capacity Resource \(pursuant to Section III.13.1.4A\)](#), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.3. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource's compliance with its critical path schedule after the Forward Capacity Auction unless the Project Sponsor previously requested pursuant to Section III.13.3.1.1 that the ISO continue to monitor that resource's compliance with its critical path schedule. However, if a New Generating Capacity Resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Resource, the ISO will not continue to monitor that resource's compliance with its critical path schedule even if that resource requested critical path schedule monitoring pursuant to Section III.13.3.1.1.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Project Sponsor does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Each critical path schedule report shall include the following:

III.13.3.2.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Project Sponsor should also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)) [and Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW \(discussed in Section III.13.3.2.2\(c\)\)](#), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

- (i) **Major Permits.** For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.
- (ii) **Project Financing Closing.** The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.
- (iii) **Major Equipment Orders.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).
- (iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades.** If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its

interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion.** The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

(c) For Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion.** The Project Sponsor shall provide documentation showing the total offered demand reduction value and net injection capability achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value and net injection capability must be complete.

(ii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Distributed Energy Resource Aggregation has been registered with the ISO, then the Project Sponsor shall also provide the Distributed Energy Resource Aggregation identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule or the feasibility that the project will achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, ~~a~~ or New Demand Capacity Resource pursuant to Section III.13.1.4.1, or a New Distributed Energy Capacity Resource pursuant to Section III.13.1.4A and clearing in that auction, the Project Sponsor must provide information in the critical path

schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Project Sponsor to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Project Sponsor does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligations.

(a) If a capacity supplier determines that a resource may not be able to demonstrate its ability to deliver the full amount of its Capacity Supply Obligation, the capacity supplier may take actions to cover all or part of the Capacity Supply Obligation for any portion of the Capacity Commitment Period, as follows:

(i) A capacity supplier may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4.

(ii) A capacity supplier may cover its Capacity Supply Obligation through one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(iii) A capacity supplier that has qualified a resource pursuant to Section III.13.1.1.1.2 may cover its Capacity Supply Obligation by electing, no later than ten Business Days prior to the

offer and bid deadline for the third annual reconfiguration auction prior to the start of the applicable Capacity Commitment Period, to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource for up to two Capacity Commitment Periods. If an election is made to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource, the capacity supplier with the resource that was previously counted as a capacity resource shall be required to comply with the requirements set forth in Section III.13.6.1 so long as it continues to cover for the New Generating Capacity Resource.

(b) During a Capacity Commitment Period, a failure to cover charge will apply to any capacity resource that has not demonstrated the ability to deliver the full amount of its Capacity Supply Obligation by the end of an Obligation Month. The failure to cover charge is the difference between a resource's monthly Capacity Supply Obligation and its Maximum Demonstrated Output, multiplied by the Failure to Cover Charge Rate, where:

Maximum Demonstrated Output Period

Maximum Demonstrated Output Period is the period beginning six years prior to the start of the applicable Capacity Commitment Period and ending with the most recently completed calendar month in the Capacity Commitment Period, including all prior months in the Capacity Commitment Period.

Provided that, for a resource that has previously been counted as a capacity resource and for which an election has been made to participate as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2, and for which a cover election has been made pursuant to Section III.13.3.4(a)(iii), then: (1) the Maximum Demonstrated Output Period will be the Maximum Demonstrated Output Period of the resource that has been previously counted as capacity, and; (2) the Maximum Demonstrated Output Period of the New Generating Capacity Resource will begin on the earlier of: (i) the date that the resource that has previously been counted as a capacity resource began any outage as provided in Section III.13.1.1.1.2, and; (ii) the date that the New Generating Capacity Resource commenced Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

Failure to Cover Charge Rate

For Capacity Commitment Periods beginning prior to June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the higher of the Capacity Clearing Price and the clearing price in any annual reconfiguration auction for that Capacity Commitment Period.

For Capacity Commitment Periods beginning on or after June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the price determined by a second clearing of the third annual reconfiguration auction prior to the start of the Capacity Commitment Period in which the aggregated zonal quantities of undemonstrated Capacity Supply Obligation, as of the completion of the third annual reconfiguration auction, and as determined pursuant to Section III.13.3.4 (b), are included as demand bids at the Forward Capacity Auction Starting Price for each applicable Capacity Zone.

Provided that, if an existing resource is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the undemonstrated Capacity Supply Obligation for the New Generating Capacity Resource is the difference between the existing resource's Maximum Demonstrated Output and the new resource's Capacity Supply Obligation.

Maximum Demonstrated Output

The Maximum Demonstrated Output is the sum of the highest output levels achieved by each Generator Asset associated with a Generating Capacity Resource, each Demand Response Asset associated with an Active Demand Capacity Resources, ~~and~~ assets associated with a Seasonal Peak Demand Resource or On-Peak Demand Resource, and each Distributed Energy Resource Aggregation associated with a Distributed Energy Capacity Resources during the Maximum Demonstrated Output Period as specified below. The minimum Maximum Demonstrated Output for all assets is zero.

Provided that, if a resource that was previously counted as capacity is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the Maximum Demonstrated Output is the sum of the highest aggregate output level achieved by each asset associated with the resource that has previously been counted as capacity during the Maximum Demonstrated Output Period.

At the asset level, Maximum Demonstrated Output is calculated as follows:

Demand Response Assets associated with an Active Demand Capacity Resource: The Maximum Demonstrated Output for dates occurring prior to June 1, 2018 is the highest audit value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses. The Maximum Demonstrated Output for dates occurring on or after to June 1, 2018 will be equal to the highest demand reduction calculated, pursuant to Section III.8.4, in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Distributed Generation associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly metered output in the Maximum Demonstrated Output Period after the resource has completed testing and has achieved commercial operation, increased by average avoided peak transmission and distribution losses for non-Net Supply.

Load Management associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly demand reduction value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Energy Efficiency associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest reported monthly performance value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses.

Generator Assets: The Maximum Demonstrated Output for dates occurring prior to March 1, 2017 is the highest hourly Revenue Quality Metering in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). The Maximum Demonstrated Output for dates occurring on or after March 1, 2017 is the highest Metered Quantity for Settlement in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

If a single Generator Asset is split into two or more new Generator Assets, the Maximum Demonstrated Output associated with the single Generation Asset will be prorated among the new assets based on their summer maximum net output. If multiple Generator Assets are consolidated to fewer assets, the Maximum Demonstrated Output of the Generator Assets that are being consolidated will be allocated to the consolidated assets based on the summer maximum net output.

Import Capacity Resources: For an Import Capacity Resource that is backed by external generation that has not achieved commercial operation at the time of qualification, in part or entirely, the Maximum Demonstrated Output is the highest revenue quality metered output for a five-minute or greater interval after the resource has completed testing and has achieved commercial operation. Provided that, the Maximum Demonstrated Output of an Import Capacity Resource associated with an Elective Transmission Upgrade may be limited by the highest demonstrated capability of the Elective Transmission Upgrade after the Elective Transmission Upgrade has completed testing and has achieved commercial operation.

[Distributed Energy Resource Aggregations associated with a Distributed Energy Capacity Resource: The Maximum Demonstrated Output is the sum of the highest output levels achieved by each asset associated with the Distributed Energy Capacity Resource during the Maximum Demonstrated Output Period, pursuant to Section III.13.3.4.](#)

III.13.3.4A Termination of Capacity Supply Obligations.

If a Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if a Project Sponsor covers a Capacity Supply Obligation for two Capacity Commitment Periods, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any

financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

If a resource's Capacity Supply Obligation that was acquired in a substitution auction at a negative price is withdrawn or terminated, the Project Sponsor shall remain obligated for any settlement charges associated with the terminated Capacity Supply Obligation for the Capacity Commitment Period.

III.13.3.5. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's Capacity Supply Obligation as described in Section III.13.3.4A, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4A.

III.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved FCM Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment

Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the resource's ability to achieve FCM Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Sections III.13.3.4(b), III.13.6 and III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves FCM Commercial Operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and 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) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7). A Project Sponsor will not take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4(a), but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an

additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.3.8. FCM Commercial Operation.

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, subject to the requirements of Section III.13.6.1.5.3(b).

(c) For an Import Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon demonstration that the Import Capacity Resource described in the New Capacity Qualification Package has achieved its full Qualified Capacity.

(d) For a Distributed Energy Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Distributed Energy Capacity Resource described in the New Distributed Energy Capacity Resource Qualification Package has achieved its full demand deviation value and net injection capability, subject to the requirements of Section III.13.6.1.7.3 and below.

(i) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value and net injection capability greater than 5 MW at a single Retail Delivery Point, these facilities shall map exactly to how the Distributed Energy Capacity Resource was qualified.

(ii) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value, to become fully commercial, the nameplate of each technology within the Distributed Energy Resource Aggregations mapped to the Distributed Energy Capacity Resource must be at least 70% of the expected nameplate of each technology used to support the Distributed Energy Capacity Resource Qualified Capacity.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of *Appendix A* of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated

Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction, or a demand bid that cleared in a substitution auction, for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period

and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources Backed By an External Control Area.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.3.1. Import Capacity Resources Backed by One or More External Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the greater of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements

in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4. Demand Capacity Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or

permanently de-list prior to the start of the relevant Capacity Commitment Period) that is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any winter capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) that is

expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.1.5.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.5.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Import Capacity Resources.

III.13.4.2.1.2.2.3.1 Import Capacity Resources Backed by an External Control Area.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October.

III.13.4.2.1.2.2.3.2. Import Capacity Resources Backed by One or More External Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the lesser of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined by the most recent Forward Capacity Auction that does not reflect a change to the Import Capacity Resource applicable to that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4. Demand Capacity Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined summer Qualified Capacity and (2) its summer Seasonal DR Audit value or summer Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined winter Qualified Capacity and (2) its winter Seasonal DR Audit value or winter Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period and increased by average avoided peak transmission and distribution losses) and any winter capacity that has cleared in a Forward Capacity Auction and not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.2.5.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DECR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.5.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DECR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved FCM Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values (for Capacity Commitment Periods beginning on or before June 1, 2019) or the least of these 12 values (for Capacity Commitment Periods beginning on or after June 1, 2020), if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by:

- (1) for Capacity Commitment Periods beginning on or before June 1, 2019, more than the lesser of:
 - (i) 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or;
 - (ii) 40 MW;
- (2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, more than the lesser of:
 - (i) the greater of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;

- (ii) 40 MW;
- (3) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:
 - (i) the greater of 10 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;
 - (ii) 10 MW;

then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to:

- (1) for Capacity Commitment Periods beginning prior to June 1, 2020, the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3;
- (2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:
 - (i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.8), and;
 - (ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 40 MW;
- (3) for Capacity Commitment Periods beginning on or after June 1, 2023, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:

- (i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.9), and;
- (ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 10 MW.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource may not submit a supply offer for a monthly reconfiguration auction unless it is expected to achieve FCM Commercial Operation prior to the end of the relevant Obligation Month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. A resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between the values determined pursuant to subsections (a) and (b) below:

(a) The resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period or, where the resource did not qualify for the third annual reconfiguration auction for the relevant Capacity Commitment Period, the quantity of MW either being monitored by the ISO in accordance with Section III.13.3 (provided that all applicable Financial Assurance requirements have been met and the resource is expected to achieve all its critical path schedule milestones prior to the end of the relevant Obligation Month in accordance with posted schedules) or the amount of capacity that achieved all its critical path schedule milestones after the third annual reconfiguration qualification deadline; provided that the value determined pursuant to this subsection (a) shall be limited by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f) or, for a Demand Capacity Resource, the amount of Qualified Capacity for the relevant Capacity Commitment Period.

(b) The amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, ~~or~~ Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

- (a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.
- (b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.
- (c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with demand bids that would otherwise clear to ensure reliability standards will remain

satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, ~~or Demand Response Resource,~~ [or Demand Response Distributed Energy Resource Aggregation](#) outage information, and will include transmission security studies. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. [Reserved.]

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, 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.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction

Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

The first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period.

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction for Capacity Commitment Periods beginning before June 1, 2020, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. For each monthly reconfiguration auction for Capacity Commitment Periods beginning or after June 1, 2020, the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.13.2.2.2 and Section III.13.2.2.3, and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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,~~ [or Demand Response Distributed Energy Resource Aggregation](#) 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 settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. 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 monthly basis during the applicable Capacity Commitment Period. The monthly payment amount 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.13.6.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.13.6.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day- Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.13.6.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers will equal that level and shall be offered into both the Day-Ahead Energy Market and

Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

(i) the sum of the resource’s notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours; or

(b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.13.6.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy 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.

III.13.6.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

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

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with 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.](#)

[\(c\) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.](#)

[\(d\) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.](#)

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. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.13.6.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day- Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire

offer, up to the maximum capability 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 so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.13.6.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with 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 an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, 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.13.6.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.1.7.3.

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, or a Distributed Energy 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:

(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:

$$\text{Hourly PER}(\$/\text{kW}) = [(\text{LMP} - \text{Adjusted Hourly PER Strike Price}) * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

Where:

$$\text{Adjusted Hourly PER Strike Price} = \text{Strike Price} + \text{Hourly PER Adjustment}$$

$$\text{Hourly PER Adjustment} = \text{average of Five-Minute PER Strike Price Adjustment values}$$

$$\text{Five-Minute PER Strike Price Adjustment} = \text{MAX} (\text{Thirty-Minute Operating Reserve clearing price} - \$500/\text{MWh}, 0) + \text{MAX} (\text{Ten-Minute Non-Spinning Reserve clearing price} - \text{Thirty-Minute Operating Reserve clearing price} - \$850/\text{MWh}, 0).$$

Strike Price = as defined below

Scaling Factor = as defined below

Availability Factor = as defined below

For all other hours:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{LMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

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_{location of the interface} - Capacity Clearing Price_{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_{location of the interface} - Capacity Clearing Price_{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.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; 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. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation 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 or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation 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 or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; 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:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{FCAcp} - \text{FCAsp}) - (12 \text{ months} \times \text{FCAcp})]$$

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 of the Obligation Month shall be subject to the following charges and adjustments:

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 III.13.7.5.1.1.1(b), III.13.7.5.1.1.2(b), III.13.7.5.1.1.3(b), III.13.7.5.1.1.6(b), III.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 III.13.7.5.1.1.1(b), III.13.7.5.1.1.2(b), III.13.7.5.1.1.3(b), III.13.7.5.1.1.6(b), III.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 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 Capacity Load Obligation in the Capacity Zone 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 Capacity 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.

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; [when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid 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 month and 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 to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and 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, or a Demand Response Distributed Energy Resource Aggregation.

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.

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, 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	Winter
									(MW)	(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.

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.

Clean Tariff

Effective November 1, 2022

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, 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, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

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.

Curtailed 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 Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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, Demand Reduction Offers or Baseline Deviation 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 Measure 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, New Demand Capacity Resource, or New Distributed Energy 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 Distributed Energy Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.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 Distributed Energy Capacity Resource Show of Interest Form is described in Section III.13.1.4A.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 an 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, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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 Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

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.

SCHEDULE 23

**SMALL GENERATOR
INTERCONNECTION PROCEDURES**

TABLE OF CONTENTS

Section 1. Application

- 1.1 Applicability
- 1.2 Pre-Application
- 1.3 Interconnection Request
- 1.4 Site Control
- 1.5 Queue Position
- 1.6 Procedures for Transition
- 1.7 Type of Interconnection Service
- 1.8 Withdrawal

Section 2. Fast Track Process

- 2.1 Applicability
- 2.2 Initial Review
- 2.3 Customer Options Meeting
- 2.4 Supplemental Review

Section 3. Study Process

- 3.1 Applicability
- 3.2 Scoping Meeting
- 3.3 Interconnection Feasibility Study
- 3.4 Interconnection System Impact Study
- 3.5 Interconnection Facilities Study

Section 4. Provisions that Apply to All Interconnection Requests

- 4.1 Reasonable Efforts
- 4.2 Disputes
- 4.3 Interconnection Metering
- 4.4 Commissioning
- 4.5 Confidentiality
- 4.6 Comparability
- 4.7 Record Retention
- 4.8 SGIA
- 4.9 Coordination with Affected Systems
- 4.10 Evaluation of a Small Generating Facility Interconnection Request

Attachment 1 – Glossary of Terms

Attachment 2 – Small Generator Interconnection Request

Attachment 3 – Certification Codes and Standards

Attachment 4 – Certification of Small Generator Equipment Packages

Attachment 5 – 10 kW Inverter Process

Attachment 6 – Interconnection Feasibility Study Agreement

Attachment 7 – Interconnection System Impact Study Agreement

Attachment 8 – Interconnection Facilities Study Agreement

EXHIBIT 1 - Small Generator Interconnection Agreement (SGIA)

SECTION 1. APPLICATION

1.1 Applicability

1.1.1 The Small Generator Interconnection Procedures (“SGIP”) and Small Generator Interconnection Agreement (“SGIA”) shall apply to Interconnection Requests, as defined in Attachment 1, pertaining to Small Generating Facilities, except that the SGIP and SGIA shall not apply to: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer’s site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility’s owner intent is to sell 100% of the Qualifying Facility’s output to its interconnected electric utility; or (iv) a Distributed Energy Resource that will be participating in the wholesale market exclusively through a Distributed Energy Resource Aggregation. In the event the SGIP and SGIA do not apply, the Interconnection Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections.

A Distributed Energy Resource reviewed as part of a Distributed Energy Capacity Resource that qualifies in any Forward Capacity Auction that takes place prior to the effective date of Section III.6 (Distributed Energy Resource Aggregations), shall not be subject to the SGIP, provided that: i) the Distributed Energy Resource meets the requirements of, and is included in the Distributed Energy Capacity Resource as a single-resource Distributed Energy Resource Aggregation, ii) the Distributed Energy Capacity Resource was qualified as a resource composed of one or more Distributed Energy Resource Aggregations that are each single-resource aggregations; iii) each underlying Distributed Energy Resource has a valid state interconnection agreement, and iv) each of the underlying Distributed Energy Resources has received approval from the ISO for a Proposed Plan Application pursuant to Section I.3.9 of the Tariff, if applicable. Each Distributed Energy Resource Aggregation in such a Distributed Energy Capacity Resource shall comply with all requirements of Section III.6 of the Tariff (Distributed Energy Resource Aggregations) following its effective date.

A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Interconnecting Transmission Owner’s Distribution System that is part of

the Administered Transmission System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) (solely as a Network Resource) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures. To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for the purposes of generator interconnections under this Schedule 23. Capitalized terms in Schedule 23 that are not defined in Attachment 1 or the body of these procedures shall have the meanings specified in Section I.2.2 of the Tariff.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to May 9, 2006.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the System Operator's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The System Operator shall respond within fifteen (15) Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects all ISOs/RTOs, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the SGIA.

1.2 Pre-Application

1.2.1 The System Operator shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The names, telephone numbers, and e-mail addresses of the System Operator's contact employees or offices shall be made available on the System Operator's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Administered Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The System Operator shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form to the System Operator along with a non-refundable fee of \$500 for a pre-application report on a proposed project at a specific site. Within two (2) Business Days of receiving the pre-application report request form, the System Operator shall provide a copy of the pre-application request form to the Interconnecting Transmission Owner. The System Operator in conjunction with the Interconnecting Transmission Owner shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within twenty (20) Business Days of receipt of the completed request form and payment of the \$500 fee. The pre-application report produced by the System Operator in conjunction with the Interconnecting Transmission Owner is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Administered Transmission System. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3 Using the information provided in the pre-application report request form in section 1.2.2., the System Operator in conjunction with the Interconnecting Transmission Owner will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. The selection by the System Operator in conjunction with the Interconnecting Transmission Owner does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. The Interconnecting Transmission Owner shall be responsible for determining whether the proposed Point of Interconnection is on a distribution facility that is subject to the Tariff. If the pre-application report request form seeks information about a Point of Interconnection that is on a distribution facility that is not subject to the Tariff, the Interconnection Customer shall follow the applicable state tariff, rules or procedures regarding generator interconnections. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the System Operator or the Interconnecting Transmission Owner to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the System Operator in conjunction with the Interconnecting Transmission Owner cannot complete all or some of a pre-application report due to lack of available data, the System Operator in conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the System Operator in conjunction with the Interconnecting Transmission Owner shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

1.3.1 Initiating an Interconnection Request

To initiate and establish a valid Interconnection Request, the Interconnection Customer shall submit all of the following to the System Operator in the manner specified in the Interconnection Request contained in Attachment 2 to this SGIP: (i) the processing fee or deposit specified in the Interconnection Request, (ii)

a completed Interconnection Request in the form of Attachment 2, and (iii) documentation of Site Control in the form specified in Section 1.4 of this SGIP.

The Interconnection Customer must submit a separate Interconnection Request for each site. The Interconnection Customer must comply with the requirements specified in this Section 1.3.1 for each Interconnection Request even when more than one request is submitted for a single site.

1.3.2 Acknowledgement of Interconnection Request

The System Operator shall acknowledge receipt of the Interconnection Request within three (3) Business Days of receipt of the request and attach a copy of the Interconnection Request to the acknowledgement.

Within three (3) Business Days of receiving the Interconnection Request, the System Operator shall provide a copy of the Interconnection Request to the Interconnecting Transmission Owner. If such request is to interconnect to a distribution facility, the Interconnecting Transmission Owner shall be responsible for determining whether the distribution facility is subject to the Tariff.

1.3.3 Deficiencies in Interconnection Request

An Interconnection Request will not be considered a valid request until all items in Section 1.3.1 have been received by the System Operator. If an Interconnection Request fails to meet the requirements set forth in Section 1.3.1, the System Operator shall notify the Interconnection Customer within ten (10) Business Days of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the System Operator the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 1.3.3 shall be treated in accordance with Section 1.8.

1.3.4 All fees or deposits that must be submitted to the System Operator under this SGIP, must be delivered to the System Operator's bank account by electronic transfer within the period specified in the respective provision. A deposit will not be considered received until it is in the System Operator's bank account.

1.4 Site Control

Documentation of site control must be submitted with the Interconnection Request. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a

modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. Site control may be demonstrated through:

1.4.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.4.2 An option to purchase or acquire an easement, a license or a leasehold interest in the site for such purpose; or

1.4.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose; or

1.4.4 Filed applications for required permits to site on federal or state property.

1.5 Queue Position

1.5.1 **General.** The System Operator shall assign a Queue Position based upon the date- and time-stamp of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of information on the application form in Attachment 2 to this SGIP, and Interconnection Customer provides such information in accordance with Section 1.3.3, then the System Operator shall assign Interconnection Customer a Queue Position based on the date the application form was originally submitted.

Except as otherwise provided in this Section 1.5, the Queue Position of each Interconnection Request will be used to determine: (i) the order of performing the Interconnection Studies; (ii) the order in which Interconnection Requests will be included in the CSIS and CFAC; (iii) the order in which Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service will be included in the CNR Group Study; and (iv) the cost responsibility for the Interconnection Facilities and upgrades necessary to accommodate the Interconnection Request. The System Operator shall maintain a single queue. At the System Operator's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

A CSIS and CFAC shall include the Interconnection Requests that were identified as eligible to participate in the CSIS and CFAC and met the associated requirements for inclusion in said studies in accordance with Section 1.5.3 of this SGIP. An Interconnection Request included in a cluster shall consider a higher queued Interconnection Request not included in the cluster. A lower queued Interconnection Request that is not included in the cluster shall consider all of the higher queued Interconnection Requests that are part of the cluster.

1.5.2 Order of Interconnection Requests in the CNR Group Study. Participation in a CNR Group Study shall be a prerequisite to achieve CNR Interconnection Service and CNI Interconnection Service. The CNR Group Study (to be conducted in accordance with Section III.13.1.1.2.3 of the Tariff) shall include all Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service that have an associated New Capacity Show of Interest Form that was submitted during the New Capacity Show of Interest Submission Window for the purpose of qualification for participation in the same Forward Capacity Auction for a Capacity Commitment Period, in accordance with Section III.13.1.1.2 of the Tariff, as well as Long Lead Facilities in accordance with Section 3.2.3 of Schedule 22 of Section II of the Tariff. Where a CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a lower Queue Position is associated with a New Capacity Show of Interest Form that was submitted for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and another CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a higher Queue Position is not associated with a New Capacity Show of Interest Form that was submitted for qualification until a subsequent Forward Capacity Auction, the CNR Interconnection Service or CNI Interconnection Service Interconnection Request with the lower Queue Position will be included in the CNR Group Study prior to the CNR Interconnection Service or the CNI Interconnection Service Interconnection Request with the higher Queue Position.

However, where an Interconnection Customer with a CNR Interconnection Service Interconnection Request submits a New Capacity Show of Interest Form for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and identifies in that New Capacity Show of Interest Form one or more Elective Transmission Upgrade Interconnection Request(s) for an Internal ETU that is not already included in the network model pursuant to Section III.12 of the Tariff for the particular Forward Capacity Auction, the CNR Interconnection Request will be included in the CNR Group Study at the lowest of the CNR Interconnection Request's or its associated Elective Transmission

Upgrade Interconnection Request(s) for the Internal ETU's Queue Position. Where multiple Interconnection Customers' CNR Interconnection Service Interconnection Requests are associated with the same lower Queue Position for an Elective Transmission Upgrade Interconnection Request for an Internal ETU in the CNR Group Study, the CNR Interconnection Request's Queue Position will be used as the tie breaker to dictate the relative order in which the CNR Interconnection Service Interconnection Request will be included in the CNR Group Study.

An Interconnection Customer with a Generating Facility or that is associated with an Import Capacity Resource in the case of an Elective Transmission Upgrade that is treated as a Conditional Qualified New Resource, in accordance with Section III.13.1.1.2.3(f) of the Tariff, may be responsible for the facilities and upgrades associated with an overlapping CNR Interconnection Service or CNI Interconnection Service Interconnection Request having a higher Queue Position if the Conditional Qualified New Resource obtains a Capacity Supply Obligation through a Forward Capacity Auction under Section III.13.2.5 of the Tariff.

An Interconnection Customer with a lower queued CNR Interconnection Service Interconnection Request for a Generating Facility or CNI Interconnection Service Interconnection Request for an Elective Transmission Upgrade that has achieved Commercial Operation and obtained CNR Interconnection Service or CNI Interconnection Service, respectively, may be responsible for additional facilities and upgrades if the related higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively. In such circumstance, Attachment 2 to the SGIA for the lower queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request shall specify the facilities and upgrades for which the Interconnection Customer shall be responsible if the higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively.

1.5.3 Clustering.

Clustering Interconnection Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable Regional System Plan in light of the New England Transmission System's capabilities for the time period under study. The System Operator may study an Interconnection Request serially to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Small Generating Facility.

1.5.3.1 Triggers for Studying Interconnection Requests in Clusters.

At the discretion of the System Operator, Interconnection Requests will be studied in clusters for the purpose of the Interconnection System Impact Study and the Interconnection Facilities Study when the combination of the following circumstances is present in the interconnection queue: (a) there are two (2) or more Interconnection Requests without completed Interconnection System Impact Studies in the same electrical part of the New England Control Area based on the requested Point of Interconnection, and (b) the System Operator has determined that none of the Interconnection Requests identified in (a) of this Section 1.5.3.1 will be able to interconnect, either individually or on a cluster basis, without the use of common significant new transmission line infrastructure rated at 115 kV AC or HVDC.

1.5.3.2 Notice of Initiation of Cluster Studies.

When the combination of the triggers specified in Section 1.5.3.1 of this SGIP are present in the interconnection queue, the System Operator will provide notice to the Planning Advisory Committee of the initiation of a cluster for studying certain Interconnection Requests under the Regional System Planning Process in accordance with Section 15.1 of Attachment K, Section II of the Tariff. The System Operator also will provide notice to the Interconnection Customers with Interconnection Requests identified in Section 1.5.3.1 of this SGIP, and at the time the System Operator notifies the Planning Advisory Committee of the initiation of a cluster, all study work for these Interconnection Requests will be suspended, and they will proceed under Section 1.5.3 of this SGIP. The System Operator will conduct Clustering in two phases. In the first phase, the System Operator will perform a CRPS to identify the CETU and associated system upgrades to enable the interconnection of potentially all of the resources proposed in the Interconnection Requests considered in Section 1.5.3.1 of this SGIP, consistent with Section 15.2 of Attachment K. In the second phase, the System Operator will conduct a CSIS and a CFAC to study the Interconnection Requests identified through the CRPS that have elected to participate in the CSIS together with the identified CETU and associated system upgrades, in accordance with this SGIP.

Within sixty (60) Calendar Days of the System Operator's notice to the Planning Advisory Committee of the initiation of the use of Clustering for studying certain Interconnection Requests under the Regional System Planning Process in accordance with Section 15.1 of Attachment K, Section II of the Tariff, Interconnection Customers with Interconnection Requests identified in Section 1.5.3.1 shall submit the technical data called for in Attachment 2 (including Attachment A, if applicable) to this SGIP to support the conduct of the CRPS.

1.5.3.3 Cluster Interconnection System Impact Study.

1.5.3.3.1 Notice of Cluster Interconnection System Impact Study Entry Deadline.

At the same time the System Operator issues the final CRPS report to the Planning Advisory Committee in accordance with Section 15.4 of Attachment K, the System Operator will provide notice of the entry deadline for the CSIS (the “Cluster Entry Deadline”) to the Interconnection Customers with Interconnection Requests identified in the final CRPS report as eligible to participate in the CSIS. The Cluster Entry Deadline shall be thirty (30) Calendar Days from the posting of the final CRPS report.

1.5.3.3.2 Cluster Interconnection System Impact Study Entry Requirements.

All Interconnection Requests identified in the final CRPS report, by Queue Position as assigned in accordance with Section 1.5.1 of this SGIP, shall be eligible to be studied together in the CSIS.

1.5.3.3.2.1 Cluster Entry Deadline Election. By the Cluster Entry Deadline, an Interconnection Customer with an Interconnection Request identified as eligible to be studied in the CSIS must, in writing:

- (i) withdraw the Interconnection Request, pursuant to Section 1.8;
- (ii) request that the System Operator re-assign the Interconnection Customer’s Interconnection Request a new Queue Position at the bottom of the queue as of the Cluster Entry Deadline in relative order with any other Interconnection Requests requesting to be re-queued under this Section 1.5.3.3.2.1; or
- (iii) request to be included in the CSIS and meet the CSIS entry requirements specified in Section 1.5.3.3.2.2.

If, by the Cluster Entry Deadline, Interconnection Customer fails to withdraw its Interconnection Request, request to be re-assigned a Queue Position at the bottom of the queue, or request to be included in the CSIS and meet the CSIS entry requirements, then the Interconnection Request will be automatically withdrawn from the interconnection queue as of the Cluster Entry Deadline without further opportunity to cure. If Interconnection Customer elects option (iii) and does not meet all of the CSIS entry requirements specified in Section 1.5.3.3.2.2 by the Cluster Entry Deadline, the Interconnection Request will be automatically withdrawn from the interconnection queue as of the Cluster Entry Deadline without further opportunity to cure. If an initial Cluster Participation Deposit had been submitted as part of the incomplete CSIS entry requirements submission, the initial Cluster Participation Deposit will be refunded at the time the Interconnection Request is withdrawn.

1.5.3.3.2.2. CSIS Entry Requirements.

An Interconnection Customer with an Interconnection Request identified in the final CRPS report as eligible to be studied in the CSIS that elects option (iii) under Section 1.5.3.3.2.1 must meet the following CSIS entry requirements in order to be included in the CSIS:

(1) Cluster System Impact Study Application. By the Cluster Entry Deadline, Interconnection Customer must submit to the System Operator, a completed Cluster System Impact Study Application in the form specified in Attachment 2, Attachment A-1 to this SGIP requesting the inclusion of the Interconnection Request in the CSIS;

(2) System Impact Study Agreement, Study Deposit, Technical Data, and Site Control. If an Interconnection Feasibility Study Agreement or an Interconnection System Impact Study Agreement has been executed prior to the issuance of the final CRPS report identifying the Interconnection Request as eligible for inclusion in a CSIS, such agreement shall terminate upon execution of a new Interconnection System Impact Study Agreement in accordance with this Section 1.5.3.3.2.2, and any unused balance of the study deposit associated with the terminated agreement shall be applied toward the study deposit associated with the new Interconnection System Impact Study Agreement.

Within fifteen (15) Business Days following the Cluster Entry Deadline, the System Operator and Interconnecting Transmission Owner will provide to Interconnection Customer an Interconnection System Impact Study Agreement, including a non-binding good faith estimate of the costs and timeframe for commencing and completing the CSIS.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the System Operator no later than thirty (30) Calendar Days after receipt along with continued demonstration of Site Control, the technical data called for in Attachment 2 (including Attachment A, if applicable), and a refundable study deposit, to the extent that any additional study deposit is required, in accordance with Section 3.4.2 of this SGIP.

(3) Cluster Participation Deposit. By the Cluster Entry Deadline, Interconnection Customer must also submit to the System Operator an initial Cluster Participation Deposit equal to five (5) percent of the

Interconnection Customer's cost allocation responsibility for the CETU and associated system upgrades to be determined based on the cost estimates provided in the final CRPS report. If the System Operator subsequently identifies that an Internal ETU has met the requirements to take the place of a CETU, or portion thereof, pursuant to Section 1.5.3.3.3.4 of this SGIP, the initial Cluster Participation Deposit will be reduced to exclude the costs associated with the CETU, or portion thereof, that is being replaced by the Internal ETU, and the Interconnection Customer shall be refunded the corresponding amount. Cost allocation of the CETU and associated upgrades shall be in accordance with Schedule 11, Section II of this Tariff.

The initial Cluster Participation Deposit will be fully refunded (with interest to be calculated in accordance with Section 1.8 of this SGIP) to Interconnection Customer with an Interconnection Request that met the cluster entry requirements: (i) if the cluster is initially undersubscribed by more than ten (10) percent of the quantity of megawatts that the CETU developed through the CRPS was designed to enable and the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 1.8, before the CSIS starts, (ii) if the CSIS is initially oversubscribed as described in Section 1.5.3.3.3.2 of this SGIP (e.g., the CETU developed through the CRPS is designed to enable 1,000 MW and more than 1,000 MW meet the CSIS entry requirements by the Cluster Entry Deadline), in which case the Cluster Participation Deposits will be refunded to Interconnection Customers with Interconnection Requests corresponding to the oversubscribed megawatt quantities, (iii) if the cost estimates for the CETU and the associated system upgrades provided in the final CRPS report for the entire cluster have increased by twenty-five (25) percent or more when compared to the cost estimates provided in the draft CSIS report or the draft CFAC report and the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 1.8, within thirty (30) Calendar Days after receipt of the draft CSIS report or the draft CFAC report in accordance with Section 3.4.5 and Section 3.5.4 of this SGIP, respectively, (iv) if less than two (2) Interconnection Requests included in the CSIS remain in the interconnection queue during the CSIS or CFAC, as applicable, in which case, the CSIS or the CFAC terminates and the remaining Interconnection Request proceeds in serial queue order, (v) at the time the Interconnection Customer with an Interconnection Request included in the CSIS provides to the Interconnecting Transmission Owner the deposit specified in Section 4.8 of this SGIP, (vi) if no Interconnection Customer with an Interconnection Request included in the cluster executes an Interconnection Agreement and provides to the Interconnecting Transmission Owner the deposit specified in Section 4.8 of this SGIP, or (vii) if all Interconnection Requests included in the cluster withdraw from the interconnection queue.

Otherwise, the initial Cluster Participation Deposit shall be non-refundable if the Interconnection Customer withdraws its Interconnection Request or the Interconnection Request is withdrawn from the interconnection queue at any time after the Cluster Entry Deadline. The non-refundable initial Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in a cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation.

1.5.3.3.3 Cluster Filling, Oversubscription and Backfilling Upon Withdrawal.

1.5.3.3.3.1 Cluster Filling. The CSIS shall be filled with all Interconnection Requests in the same electrical part of the New England Control Area relative to the CETU identified in the final CRPS report that do not yet have a completed Interconnection System Impact Study and met the CSIS entry requirements by the Cluster Entry Deadline up to the approximate megawatt quantity identified in the CRPS as potentially enabled by the CETU. The Interconnection Requests will be included in the CSIS in queue order, based on the Queue Positions assigned in accordance with Section 1.5.1 of this SGIP, relative to other eligible Interconnection Requests.

1.5.3.3.3.2 Cluster Oversubscription. If an Interconnection Customer with an Interconnection Request identified in the final CRPS report as eligible to participate in a CSIS met the CSIS entry requirements and therefore would have been eligible for inclusion in the CSIS but is excluded as a result of the quantity of megawatts identified as potentially enabled by the CETU in the final CRPS report having been exhausted in queue order under Section 1.5.3.3.3.1, (i) the Cluster Participation Deposit for the CSIS will be refunded to the Interconnection Customer, and (ii) the Interconnection Request will maintain its Queue Position. If there are two (2) or more Interconnection Requests after the CSIS is filled, the System Operator will initiate another cluster to identify the transmission infrastructure to enable the interconnection of another round of Interconnection Requests consistent with Section 15.1 of Attachment K.

1.5.3.3.3.3 Cluster Backfilling Upon Withdrawal. Upon withdrawal of an Interconnection Request that is included in the CSIS, the System Operator will backfill the CSIS, in queue order, with later-queued Interconnection Requests consistent with the methodology used to fill the original CSIS as specified in Section 1.5.3.3.3.1 of this SGIP. The System Operator will notify all Interconnection Customers with Interconnection Requests identified by the System Operator as eligible for backfilling that the respective Small Generating Facility (or part thereof) proposed in the Interconnection Request is eligible to

participate in the CSIS, and the Interconnection Customer shall have thirty (30) Calendar Days from receipt of System Operator's notice to withdraw its Interconnection Request, request to be re-assigned a Queue Position at the bottom of the queue, or accept the inclusion of the Interconnection Request (or part thereof, in which case the Interconnection Customer shall modify the Interconnection Request to reflect the appropriate reduction) in the CSIS and meet the CSIS entry requirements, consistent with Section 1.5.3.3.2 of this SGIP. If the Interconnection Customer does not make one of these three elections and complete the associated requirements by the thirtieth Calendar Day, the System Operator shall automatically withdraw the Interconnection Request from the interconnection queue without further opportunity to cure and consider other later-queued Interconnection Requests.

1.5.3.3.4 Scope of Cluster Interconnection System Impact Study. Except as otherwise provided in this Section 1.5.3.3.4, the CSIS shall be conducted in accordance with Sections 3.4.3 and 3.4.4 of this SGIP. The Study Case developed for the CSIS shall also include the CETU and associated system upgrades identified in the final CRPS report. An Internal ETU can be considered, and included in the CSIS, in place of a CETU, or portion thereof, if all of the Interconnection Customers with Interconnection Requests included in the cluster that the ISO has determined need to use the Internal ETU have indicated in the Cluster Application Form or with the executed Interconnection System Impact Study Agreement that they have a contractual commitment in place providing for the Interconnection Customers to fund and the right to use the Internal ETU. The CSIS shall evaluate the proposed interconnections to the New England Transmission System under the NC Interconnection Standard consistent with Section 1.7.2 of this SGIP and as detailed in the ISO New England Planning Procedures. Consistent with the NC Interconnection Standard, the evaluation will include conditions where the projects proposed in the Interconnection Requests that are included in the CSIS are not dispatched against each other if they do not share a system constraint that would provide the basis for a redispach condition. The CSIS shall consist of the analysis specified in Section 3.4.3 of this SGIP except for analysis associated with an Interconnection Feasibility Study or a preliminary, non-binding, analysis. An Interconnection Customer with an Interconnection Request being studied as part of the CSIS cannot elect to have the Interconnection Feasibility Study or a preliminary, non-binding, analysis performed as part of the CSIS.

1.5.3.3.5. Restudy of Cluster Interconnection System Impact Study. In addition to the circumstances specified in Section 3.4.6 of this SGIP, a re-study of the CSIS is required due to the withdrawal of an Interconnection Request that had been included in the CSIS. Upon withdrawal of an Interconnection Request that had been included in the CSIS, the System Operator will backfill the CSIS with eligible

Interconnection Requests pursuant to Section 1.5.3.3.3.3. A re-study will be conducted to determine if there are any changes in the upgrades identified during the CSIS with the exception of the CETU identified in the final CRPS report, which shall remain configured consistent with the megawatt quantity(ies) considered in the final CRPS report.

1.5.3.4. Cluster Interconnection Facilities Study.

Notwithstanding any other provision in this SGIP, an Interconnection Customer with an Interconnection Request included in a completed CSIS will not be eligible to waive the, or request a separate, CFAC. All Interconnection Customers with an Interconnection Request included in a completed CSIS shall be studied together in the CFAC for the purpose of implementing the conclusions of the CSIS with respect to non-sole use facilities.

1.5.3.4.1 Cluster Interconnection Facilities Study Entry Requirements.

An Interconnection Customer with an Interconnection Request that was included in a completed CSIS shall execute an Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to the System Operator, together with the required technical data and refundable deposit for the Interconnection Facilities Study as specified in Section 3.5.1 of this SGIP.

1.5.3.4.2. Scope of Interconnection Facilities Study. The CFAC will be conducted in accordance with Sections 3.5.2 and 3.5.3 of this SGIP based on a +/- 20 percent good faith cost estimate.

1.5.3.4.3 Re-study of the Interconnection Facilities Study. In addition to the circumstances specified in Section 3.5.5 of this SGIP, a re-study of the CFAC is required due to the withdrawal of an Interconnection Request that had been included in the CFAC. Upon withdrawal of an Interconnection Request included in the CFAC, the System Operator will backfill the CSIS with eligible Interconnection Requests pursuant to Section 1.5.3.3.3.3. A re-study of the CSIS and CFAC will be conducted to determine if there are any changes in the upgrades identified during the CSIS and CFAC with the exception of the CETU identified in the final CRPS report, which shall remain consistent with the megawatt quantity(ies) considered in the final CRPS report.

1.5.3.4.4 Additional Cluster Participation Deposit. Within thirty (30) Calendar Days after receipt of the final CFAC report in accordance with Section 3.5.3 of this SGIP, an Interconnection Customer with an Interconnection Request included in the CFAC shall submit to the System Operator an additional

Cluster Participation Deposit equal to five (5) percent of the Interconnection Customer's cost allocation responsibility for the CETU and associated system upgrades to be determined based on the cost estimates provided in the final CFAC report. Cost allocation of the CETU and associated upgrades shall be in accordance with Schedule 11, Section II of this Tariff.

The additional Cluster Participation Deposit provided under this Section 1.5.3.4.4 will be fully refunded (with interest to be calculated in accordance with Section 1.8 of this SGIP) to Interconnection Customer that submitted the additional Cluster Participation Deposit if the conditions specified in Sections 1.5.3.3.2.2(3)(v), (vi), or (vii) above occur.

Otherwise, the additional Cluster Participation Deposit shall be non-refundable if the Interconnection Customer withdraws its Interconnection Request or the Interconnection Request is withdrawn from the interconnection queue. The non-refundable additional Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in a cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation.

1.5.4 Transferability of Queue Position. An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change. The Interconnection Customer must notify the System Operator, in writing, of any transfers of Queue Position and must provide the System Operator with the transferee's contact information, and System Operator shall notify Interconnecting Transmission Owner and any Affected Parties of the same.

1.5.5 Modifications. Any modification to the Interconnection Request, including the information provided in the attachments, and to the machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the System Operator, in consultation with the Interconnecting Transmission Owner, and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the change are undertaken. An Interconnection Customer may decrease the electrical output of a proposed Small Generating Facility after the Cluster Entry Deadline specified in Section 1.5.3.3.1 of this SGIP; however, the requesting Interconnection Customer remains responsible for costs corresponding to the

megawatt quantity requested as of the Cluster Entry Deadline. A request to: (1) increase the energy capability or capacity capability output of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP shall require a new Interconnection Request for the incremental increase and such Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis; and (2) change from NR Interconnection Service to CNR Interconnection Service, at any time, shall require a new Interconnection Request for CNR Interconnection Service and such Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis.

Notwithstanding the foregoing, an Interconnection Customer with an Interconnection Request for CNR Interconnection Service has until the Forward Capacity Auction for which the associated Capacity Commitment Period begins less than seven (7) years from the date of the original Interconnection Request for CNR Interconnection Service to clear the entire megawatt amount for which the CNR Interconnection Service was requested (or as that amount has been modified in accordance with this Section 1.5.5). A new Interconnection Request for CNR Interconnection Service will be required for the Generating Facility to participate in any subsequent auctions.

1.6 Procedures for Transition

1.6.1 Queue Position for Pending Requests. Any Interconnection Customer assigned a Queue Position prior to November 1, 2017 shall retain that Queue Position subject to Section 1.6 of the SGIP.

1.6.1.1 If an Interconnection Study Agreement has not been executed prior to November 1, 2017, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with the version of this SGIP in effect on November 1, 2017 (or as revised thereafter).

1.6.1.2 If an Interconnection Study Agreement has been executed prior to November 1, 2017, such Interconnection Study shall be completed in accordance with the terms of such agreement.

If an Interconnection Study Agreement has been executed prior to November 1, 2017, but the Interconnection Study has not commenced, such Interconnection Study shall be completed, and any subsequent Interconnection Studies shall be processed, in accordance with the version of the SGIP in

effect on November 1, 2017. Interconnection Studies for Interconnection Requests seeking to interconnect into the Northern and Western Maine parts of the New England Control Area that do not have a completed Interconnection System Impact Study by November 1, 2017 shall be included in the Maine Resource Integration Study, which shall be the first CRPS. The Interconnection Customers identified in the Maine Resource Integration Study as eligible to participate in the associated Cluster System Impact Study shall make one of the elections and complete the associated requirements specified in Section 1.5.3.3.2 of this SGIP within thirty (30) Calendar Days from the later of November 1, 2017 or the final Maine Resource Integration Study report. If the Interconnection Customer does not make one of the elections and complete the associated requirements by the thirtieth Calendar Day, the System Operator shall automatically withdraw the Interconnection Request from the interconnection queue without further opportunity to cure.

1.6.2 Transition Period. To the extent necessary, the System Operator, Interconnection Customers with an outstanding Interconnection Request (i.e., an Interconnection Request for which an SGIA has neither been executed nor submitted to the Commission for approval prior to November 1, 2017), Interconnecting Transmission Owner and any other Affected Parties, shall transition to proceeding under the version of the SGIP in effect as of November 1, 2017 (or as revised thereafter) within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term “outstanding Interconnection Request” herein shall mean any Interconnection Request, on November 1, 2017: (i) that has been submitted, together with the required deposit and attachments, but not yet accepted by the System Operator; (ii) where the related SGIA has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding Interconnection Request as of the effective date of this SGIP may request a reasonable extension of the next applicable deadline if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension, not to exceed sixty (60) Calendar Days, shall be granted by the System Operator to the extent consistent with the intent and process provided for under this SGIP.

1.6.3 One-Time Election for CNR Interconnection Service at Queue Position Assigned Prior to February 1, 2009. An Interconnection Customer with an outstanding Interconnection Request will be

eligible to make a one-time election to be considered for CNR Interconnection Service at the Queue Position assigned prior to February 1, 2009. The Interconnection Customer's one-time election must be made by the end of the New Generating Capacity Show of Interest Submission Window for the fourth Forward Capacity Auction. Interconnection Customers requesting CNR Interconnection Service will be required to comply with the requirements for CNR Interconnection Service set forth in Section 1.7.1. Interconnection Customers requesting CNR Interconnection Service that have not received a completed Interconnection System Impact Study may request a preliminary, non-binding, analysis of potential upgrades that may be necessary for the fourth Forward Capacity Auction – the prompt or near-term auction – pursuant to Sections 3.3.2 or 3.4.3, whichever is applicable.

1.6.4 Grandfathering.

1.6.4.1 An Interconnection Customer's Generating Facility that is interconnected pursuant to an Interconnection Agreement executed or submitted to the Commission for approval prior to February 1, 2009, will maintain its status as a Network Resource with Network Resource Interconnection Service eligible to participate in the New England Markets, in accordance with the requirements of Market Rule 1, Section III of the Tariff, up to the megawatt amount specified in the Interconnection Agreement, subject to the Interconnection Customer satisfying all requirements set forth in the Interconnection Agreement and this SGIP. If the Generating Facility does not meet the criteria set forth in Section 1.6.4.3 of this SGIP, the Interconnection Customer will be eligible to make a one-time election, pursuant to Section 1.6.3, for Capacity Network Resource treatment without submitting a new Interconnection Request; however, the Interconnection Customer will be required to comply with the requirements for CNR Interconnection Service set forth in Section 1.7.1. Upon completion of the requirements to obtain CNR Interconnection Service, the Interconnection Customer's Interconnection Agreement shall be amended to conform to the SGIA in Exhibit 1 of this SGIP.

1.6.4.2 An Interconnection Customer's Generating Facility governed by an Interconnection Agreement either executed or filed with the Commission in unexecuted form prior to August 1, 2008, shall maintain the Queue Position assigned as of August 1, 2008, and be eligible to participate in the New England Markets, in accordance with the requirements in Market Rule 1, Section III of the Tariff, as in effect as of August 1, 2008, so long as the Interconnection Customer complies with all of the requirements specified in the Interconnection Agreement, including achieving the milestones associated with At-Risk Expenditures, subject to Section 1.5.5 of this SGIP.

1.6.4.3 All resources that are treated as Existing Generating Capacity Resources in the fourth Forward Capacity Auction pursuant to Section III.13 of the Tariff shall receive treatment as a CNR and obtain CNR Interconnection Service, in accordance with this SGIP, up to the CNR Capability of the resource. The grandfathered CNR Capability for these resources shall be equal to the megawatt amount established pursuant to the following hierarchy:

- (a) First, the megawatt amount specified in an Interconnection Agreement (whether executed or filed in unexecuted form with the Commission).
- (b) Second, in the absence of an Interconnection Agreement with a specified megawatt amount, the megawatt amount specified in an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision).
- (c) Third, in the absence of an Interconnection Agreement and an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision) with a specified megawatt amount, as determined by the System Operator based on the documented historic capability of the Generating Facility.

Where a resource has both an Interconnection Agreement and an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision), the lower megawatt amount will govern until the resource completes the applicable process(es) under the Tariff for obtaining the higher megawatt amount. The absence of an Interconnection Agreement or an approval pursuant to Section I.3.9 (or its predecessor provision) specifying a megawatt amount shall be confirmed by an affidavit executed by a corporate officer of the resource attesting that the resource does not have an Interconnection Agreement and/or an approval pursuant to Section I.3.9 of the Tariff (or its predecessor provision) that specifies a megawatt amount.

Where the governing document (as determined by the hierarchy set forth in 1.6.4.3) specifies a megawatt amount at an ambient temperature consistent with the definition of CNR Capability, the grandfathered CNR Capability shall be equal to that amount.

Where the governing document (as determined by the hierarchy set forth in Section 1.6.4.3) does not specify an ambient temperature, the megawatt amount will be deemed to be at the value consistent with the definition of CNR Capability.

Where the implementation of this Section 1.6.4.3 results in a CNR Capability that is different than previously had been identified, the revised CNR Capability will be applied commencing with the next Forward Capacity Auction qualification process (after the revised CNR Capability value is identified), which is initiated by the Show of Interest Window in accordance with Section III.13 of the Tariff. The revised CNR Capability will continue to govern until the resource completes the applicable process(es) for obtaining the higher megawatt amount.

1.6.4.4 All resources that are treated as Existing Generating Capacity Resources in the fourth Forward Capacity Auction pursuant to Section III.13 of the Tariff shall receive treatment as a NR and obtain NR Interconnection Services in accordance with this SGIP, up to the NR Capability of the resource. The grandfathered NR Capability shall be determined pursuant to the hierarchy set forth in Section 1.6.4.3.

Where the governing document (as described by the hierarchy set forth in Section 1.6.4.3) of a resource for which a temperature-adjustment curve is used for the claimed capability verification, as set forth in the ISO New England Manuals, specifies a megawatt amount at an ambient temperature, the grandfathered NR Capability shall be equal to a temperature-adjusted value consistent with the definition of NR Capability.

Where the governing document (as determined by the hierarchy set forth in Section 1.6.4.3) does not specify an ambient temperature, the megawatt amount will be deemed to be at the value consistent with the definition of NR Capability.

1.7 Type of Interconnection Services

At the time the Interconnection Request is submitted, the Interconnection Customer must request either CNR Interconnection Service or NR Interconnection Service, as described in Sections 1.7.1 and 1.7.2 below. An Interconnection Customer that meets the requirements to obtain CNR Interconnection Service shall obtain NR Interconnection Service up to the NR Capability upon completion of all requirements for NR Interconnection Service, including all necessary upgrades. Upon completion of all requirements for the CNR Interconnection Service, the Interconnection Customer shall also receive CNR Interconnection Service for CNR Capability. An Interconnection Customer that meets the requirements to obtain NR Interconnection Service shall receive NR Interconnection Service for the Interconnection Customer's Generating Facility NR Capability.

1.7.1 Capacity Network Resource Interconnection Service

1.7.1.1 The Product. The System Operator must conduct the necessary studies in conjunction with the Interconnecting Transmission Owner, and with other Affected Parties as appropriate and in accordance with applicable codes of conduct and confidentiality requirements, and the Interconnecting Transmission Owner and other Affected Parties as appropriate must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which CNRs are interconnected under the CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Small Generating Facility to be designated as a CNR, and to participate in the New England Markets, in accordance with the Tariff, up to the CNR Capability or as otherwise provided in the Tariff, on the same basis as existing CNRs, and to be studied as a CNR on the assumption that such a designation will occur.

1.7.1.2 The Studies. All Interconnection Studies for CNR Interconnection Service shall assure that the Interconnection Customer's Small Generating Facility satisfies the minimum characteristics required to interconnect in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System. The CNR Group Study for CNR Interconnection Service shall assure that the Interconnection Customer's Small Generating Facility can be interconnected in a manner that ensures intra-zonal deliverability by avoidance of the redispach of other CNRs and Elective Transmission Upgrades with CNI Interconnection Service, in accordance with the CC Interconnection Standard and as detailed in the ISO New England Planning Procedures. The Interconnection Request may also be studied with the New England Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the System Operator and as appropriate the Interconnecting Transmission Owner must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

1.7.1.3 Milestones for CNR Interconnection Service. In addition to the requirements set forth in this SGIP, an Interconnection Customer with an Interconnection Request for CNR Interconnection Service shall complete the following milestones prior to receiving CNR Interconnection Service for the CNR Capability, such milestones to be specified in Attachment 4 of the SGIA as either completed or to be completed: (i) submit the necessary requests for participation in the Forward Capacity Auction associated with the Generating Facility's requested Commercial Operation Date (except as modified by Agreement with the System Operator pursuant to Section 1.5.5 of this SGIP), in accordance with the provisions of

Section III.13 of the Tariff; (ii) participate in a CNR Group Study for the Forward Capacity Auction associated with the requested Generating Facility's Commercial Operation Date; (iii) qualify and receive a Capacity Supply Obligation in accordance with Section III.13 of the Tariff; and (iv) complete a re-study of the applicable Interconnection Study and CNR Group Study after the Forward Capacity Auction, Reconfiguration Auction, or bilateral transaction through which the Interconnection Customer received a Capacity Supply Obligation to determine the cost responsibility for facilities and upgrades necessary to accommodate the Interconnection Request. The re-study shall include those CNR Interconnection Service or CNI Interconnection Service Interconnection Requests with a higher Queue Position that cleared and shall exclude any upgrades that are no longer necessary as a result of existing capacity that will be retired as of the start of the Capacity Commitment Period for which the resource has received a Capacity Supply Obligation. With respect to (iv) above, if an Interconnection Study Agreement has been executed, the Interconnection Study associated with the Interconnection Study Agreement shall include the necessary analysis that would otherwise have been performed in a re-study. If the original Interconnection Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Study Agreement. If an SGIA has been either executed or filed with the Commission in unexecuted form, then the last Interconnection Study completed for the Interconnection Customer under this SGIP shall be subject to re-study. The Attachments to the SGIA shall be amended (pursuant to Article 12.2 of the SGIA) to reflect CNR Capability and the results of the re-study.

1.7.2 Network Resource Interconnection Service

1.7.2.1 The Product. The System Operator must conduct the necessary studies in conjunction with the Interconnecting Transmission Owner, and with other Affected Parties as appropriate and in accordance with applicable codes of conduct and confidentiality requirements, and the Interconnecting Transmission Owner and other Affected Parties as appropriate must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which Network Resources are interconnected under the NC Interconnection Standard. NR Interconnection Service allows the Interconnection Customer's Small Generating Facility to participate in the New England Markets in accordance with the provisions of Market Rule 1, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as other Network Resources. Notwithstanding the above, the portion of a Small Generating Facility that has been designated solely as a Network Resource interconnected under the NC Interconnection Standard cannot

be a capacity resource under Section III.13 of the Tariff, except pursuant to a new Interconnection Request for CNR Interconnection Service.

1.7.2.2 The Studies. The Interconnection Studies for an Network Resource shall assure that the Interconnection Customer's Small Generating Facility satisfies the minimum characteristics required to interconnect in a manner that avoids any significant adverse effect on reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the unit, in accordance with the NR Interconnection Standard and as detailed in the ISO New England Planning Procedures. The System Operator, in coordination with the Interconnecting Transmission Owner, may also study the New England Transmission System under non-peak load conditions.

However, upon request by the Interconnection Customer, the System Operator and as appropriate the Interconnecting Transmission Owner must explain in writing to the Interconnecting Transmission Owner why the study of non-peak load conditions is required for reliability purposes.

1.7.2.3 Milestones for NR Interconnection Service. An Interconnection Customer with an Interconnection Request for NR Interconnection Service shall complete the requirements in this SGIP prior to receiving NR Interconnection Service.

1.8 Withdrawal

1.8.1 The Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to System Operator, which System Operator will transmit to the Interconnecting Transmission Owner and any Affected Parties. In addition, if the Interconnection Customer fails to adhere to all requirements of this SGIP, except as provided in Section 4.2 (Disputes), the System Operator shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Except as otherwise provided elsewhere in this SGIP, upon receipt of such written notice, the Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cure the deficiency or to notify the System Operator of its intent to pursue dispute resolution, and the System Operator shall notify the Interconnecting Transmission Owner and any Affected Parties of the same.

1.8.2 Withdrawal shall result in the loss of the Interconnection Customer's Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during dispute resolution, the System Operator may eliminate the Interconnection Customer's Interconnection Request from the queue until such time that the outcome of dispute resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to System Operator, Interconnecting Transmission Owner, and any Affected Parties all costs prudently incurred with respect to that Interconnection Request prior to the System Operator's receipt of notice described above. The Interconnection Customer must pay all monies due before it is allowed to obtain any interconnection study data or results.

1.8.3 The System Operator shall update the OASIS Queue Position posting. The System Operator and Interconnecting Transmission Owner shall: (i) arrange to refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceeds the costs incurred; or (ii) arrange to charge to the Interconnection Customer any amount of such costs incurred that exceed the Interconnection Customer's deposit or study payments. In the event of such withdrawal, the System Operator, subject to the confidentiality provisions of Section 4.5 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information, shall provide, at Interconnection Customer's request, all information developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

SECTION 2. FAST TRACK PROCESS

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Distribution System that is part of the Administered Transmission System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than or equal to 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the System Operator in conjunction with the Interconnecting Transmission Owner has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline ¹ and ≤ 2.5 Electrical Circuit Miles from Substation ²
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and < 69 kV	≤ 4 MW	≤ 5 MW

1. For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

2. An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

2.2 Initial Review

Within fifteen (15) Business Days after the System Operator notifies the Interconnection Customer it has received a complete Interconnection Request, the System Operator in conjunction with the Interconnecting Transmission Owner shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Interconnecting Transmission Owner's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of an Interconnecting Transmission Owner's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Interconnecting Transmission Owner's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Interconnecting Transmission Owner on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved for Network Resource interconnection Service and the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer an executable SGIA within five (5) Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the System Operator in conjunction with the Interconnecting Transmission Owner determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the System Operator in

conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer an executable SGIA within five (5) Business Days after the determination. If the Interconnection Request is for Capacity Network Resource Interconnection Service, the Interconnection Customer must also comply with the milestones for CNR Interconnection Service specified in Section 1.7.1.3 of the SGIP.

2.2.4 If the proposed interconnection fails the screens, but the System Operator in conjunction with the Interconnecting Transmission Owner, does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the System Operator in conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the System Operator in conjunction with the Interconnecting Transmission Owner determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the System Operator shall notify the Interconnection Customer of that determination within five (5) Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten (10) Business Days of such determination, the System Operator shall offer to convene a customer options meeting with the Interconnection Customer and Interconnecting Transmission Owner to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the determination, or at the customer options meeting:

2.3.1 The Interconnecting Transmission Owner shall offer to perform facility modifications or minor modifications to the Interconnecting Transmission Owner's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Interconnecting Transmission Owner's electric system. If the Interconnection Customer agrees to pay for the modifications to the Interconnecting Transmission Owner's electric system, the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer with an executable SGIA within ten (10) Business Days of the customer options meeting; or

2.3.2 The System Operator shall offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 The System Operator shall obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit to the System Operator for the estimated costs of the supplemental review in the amount of the System Operator's and Interconnecting Transmission Owner's good faith estimate of the costs of such review, both within fifteen (15) Business Days of the offer. If the written agreement and deposit have not been received by the System Operator within that timeframe, the Interconnection Request shall continue to be evaluated under the section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer must specify the order in which the System Operator in conjunction with the Interconnecting Transmission Owner will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the System Operator's and the Interconnecting Transmission Owner's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within twenty (20) Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the System Operator and Interconnecting Transmission Owner will return such excess within twenty (20) Business Days of the invoice without interest.

2.4.4 Within thirty (30) Business Days following receipt of the deposit for a supplemental review, the System Operator shall (1) in conjunction with the Interconnecting Transmission Owner, perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the System Operator's and Interconnecting Transmission Owner's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of

supplemental review, the System Operator shall notify the Interconnection Customer following the failure of any of the screens, or if the System Operator in conjunction with the Interconnecting Transmission Owner is unable to perform the screen in section 2.4.4.1, within two (2) Business Days of making such determination to request Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 Minimum Load Screen: Where twelve (12) months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the System Operator in conjunction with the Interconnecting Transmission Owner shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV_systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4.4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Interconnecting Transmission Owner's electric system will be considered as part of the aggregate generation.

2.4.4.1.3 The System Operator and the Interconnecting Transmission Owner will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The System Operator in conjunction with the Interconnecting Transmission Owner shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section is uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the System Operator in conjunction with the Interconnecting Transmission Owner will provide the Interconnection Customer with an executable SGIA within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Interconnecting Transmission Owner on its own system, the SGIA shall be provided within ten (10) Business Days after the notification of the supplemental review results.

2.4.5.2 If Interconnection Facilities or minor modifications to the Interconnecting Transmission Owner's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Interconnecting Transmission Owner's electric system, the SGIA, along with a non-binding good faith estimate for the Interconnection Facilities and/or minor modifications, shall be provided to the Interconnection Customer within fifteen (15) Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than Interconnection Facilities or minor modifications to the Interconnecting Transmission Owner's system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the System Operator shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

SECTION 3. STUDY PROCESS

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Administered Transmission System if the Small Generating Facility is no

larger than 20 MW and does not meet the eligibility requirements of section 2.1 or does not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The System Operator, the Interconnecting Transmission Owner, the Interconnection Customer and the Affected Party(ies) will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. Before participating in a scoping meeting with an Interconnection Customer that is also an Affiliate, the Interconnecting Transmission Owner shall post on the OASIS an advance notice of its intent to do so.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request, including: (i) the estimated timeline for completing all applicable Interconnection Studies, (ii) exchange pertinent information including any transmission data that would reasonably be expected to impact interconnection options, (iii) analyze such information, and (iv) determine the potential feasible Points of Interconnection, and (v) to discuss any other information necessary to facilitate the administration of the Interconnection Procedures. A PSCAD model is required for all wind and inverter-based Small Generating Facilities. If a PSCAD model is required for other Small Generating Facility types, the Parties shall discuss this at the Scoping Meeting. The Parties shall discuss whether the System Operator should perform an Interconnection Feasibility Study or proceed directly to an Interconnection System Impact Study, or an Interconnection Facilities Study, or an SGIA. If the Interconnection Customer provides the technical data called for in Attachment 2 (including Attachment A, if applicable) to this SGIP with the Interconnection Request, the Parties shall discuss the detailed project design at the Scoping Meeting.

Unless the Interconnection Request has been identified to be included in a CRPS or eligible for inclusion in a CSIS, within five (5) Business Days following the scoping meeting, the Interconnection Customer shall notify the System Operator, in writing: (i) whether it wants the Interconnection Feasibility Study to be completed, as a separate and distinct study or as part of the Interconnection System Impact Study, (ii) if requesting the Interconnection Feasibility Study be completed as a separate and distinct study, which of the alternative study scopes is being selected pursuant to Section 3.3.2, and (iii) the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection for inclusion in the attachment

to the Interconnection Feasibility Study Agreement (Attachment 6), or the Interconnection System Impact Study Agreement (Attachment 7) if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested an Interconnection Feasibility Study must return the executed Interconnection Feasibility Study Agreement (or Interconnection System Impact Study Agreement if the Interconnection Customer elected not to pursue the Interconnection Feasibility Study), within fifteen (15) Business Days.

3.3 Interconnection Feasibility Study

3.3.1 Interconnection Feasibility Study Agreement. Within five (5) Business Days following the Interconnection Customer's request for an Interconnection Feasibility Study, the System Operator shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by the System Operator and Interconnecting Transmission Owner, including an outline of the scope of the Interconnection Feasibility Study and a non-binding good faith estimate of the cost to perform the Interconnection Feasibility Study. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). No later than fifteen (15) Business Days after its receipt of the Interconnection Feasibility Study Agreement, the Interconnection Customer shall execute and deliver the agreement, including completed attachments, to System Operator and the Interconnecting Transmission Owner, together with the refundable deposit of the lesser of 50 percent of the good faith estimated Interconnection Feasibility Study costs or earnest money of \$1,000. The deposit shall be applied toward the cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS. Any difference between the study deposit and the actual cost of the Interconnection Feasibility Study or the actual costs incurred by the Interconnecting Transmission Owner in developing the costs estimates in support of the CRPS shall be paid by or refunded to the Interconnection Customer. The System Operator and/or Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of the Interconnection Feasibility Study that have

been incurred by the System Operator and/or the Interconnecting Transmission Owner on the Interconnection Feasibility Study, including the development of the study agreement and its attachment(s). The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Feasibility Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. System Operator shall continue to hold any amounts on deposits until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.3.2 Scope of Interconnection Feasibility Study. The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Administered Transmission System with available data and information. The Interconnection Feasibility Study will consider the Base Cases as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission (the “Study Case” for the Interconnection Feasibility Study). An Interconnection Customer with a CNR Interconnection Request may also request that the Interconnection Feasibility Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer’s Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection Feasibility Study Agreement. The Interconnection Feasibility Study will consist of a power flow, including thermal analysis and voltage analysis, and short circuit analysis. The Interconnection Feasibility Study report will provide (i) a list of facilities and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct the Interconnection Facilities and Network Upgrades; (iii) a protection assessment to determine the required Interconnection Facilities; and may provide (iv) an evaluation of the siting of Interconnection Facilities and Network Upgrades; and (v) identification of the

likely permitting and siting process including easements and environmental work for Interconnection Facilities and Network Upgrades.

Alternatively, in the case where the Interconnection Customer requests that the Interconnection Feasibility Study be completed as a separate and distinct study, the Interconnection Customer may provide the technical data called for in Appendix 1, Attachment A with the executed Interconnection Feasibility Study Agreement and request that the Interconnection Feasibility Study consist of limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting. In this case, the Interconnection Feasibility Study report will provide (i) the study findings; and, (ii) a preliminary description of and a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study.

To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.3, the Interconnection Feasibility Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.3.3 Interconnection Feasibility Study Procedures. The System Operator in coordination with Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than thirty (30) Business Days after System Operator and Interconnecting Transmission Owner receive the fully executed Interconnection Feasibility Study Agreement, study deposit and required technical data in accordance with Section 3.3.1. At the request of the Interconnection Customer or at any time the System Operator or the Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the System Operator is unable to complete the Interconnection Feasibility Study within that time period, the System Operator shall notify the

Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

3.3.4 Meeting with Parties. Within ten (10) Business Days of providing an Interconnection Feasibility Study report to the Interconnection Customer, the System Operator will convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements to discuss the results of the Interconnection Feasibility Study.

3.3.5 Re-Study. If re-study of the Interconnection Feasibility Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resources(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Feasibility Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Feasibility Study Agreement. The Interconnection Customer shall have the option to waive the re-study and elect to have the re-study performed as part of its Interconnection System Impact Study. The Interconnection Customer shall provide written notice of the waiver and election of moving directly to the Interconnection System Impact Study within five (5) Business Days of receiving notice from the System Operator of the required re-study.

3.4 Interconnection System Impact Study

3.4.1 Interconnection System Impact Study Agreement. Within five (5) Business Days following the Interconnection Feasibility Study results meeting, the System Operator and Interconnecting Transmission Owner shall provide to Interconnection Customer the Interconnection System Impact Study Agreement, which includes a non-binding good faith estimate of the cost and timeframe to perform the

Interconnection System Impact Study. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA.

3.4.2 Execution of Interconnection System Impact Study Agreement. The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement, including completed attachments, to the System Operator no later than fifteen (15) Business Days after its receipt along with (1) demonstration of Site Control, (2) a refundable deposit of 50 percent of the good faith estimated cost for the transmission portion of the Interconnection System Impact Study and 100 percent of the good faith estimated cost for the distribution portion of the Interconnection System Impact Study, and (3) a PSCAD model if one was determined to be needed at the Scoping Meeting; provided that if a PSCAD model was determined to be needed for the non-wind or non-inverter-based Small Generating Facility at the Scoping Meeting, then the Interconnection Customer shall have ninety (90) Calendar Days from the execution of the System Impact Study Agreement to provide the PSCAD model. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. The deposit shall be applied toward the cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA. For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS. Any difference between the study deposit and the actual cost of the Interconnection System Impact Study or the actual costs incurred by the Interconnecting Transmission Owner in developing the costs estimates in support of the CRPS shall be paid by or refunded to the Interconnection Customer. The System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of Interconnection System Impact Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the System Impact Study, including the study agreement and its attachment(s) and the SGIA. In the case of Clustering, CSIS costs that are associated with an individual Interconnection Request assessed within the CSIS will be

charged directly to that Interconnection Customer. CSIS costs that are associated with the CSIS as a whole will be divided equally, on a per-project basis, among the Interconnection Customers in the cluster.

The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the transmission portion of the Interconnection System Impact Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold the amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.4.3 Scope of Interconnection System Impact Study. The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability and operation of the New England Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission (the “Study Case” for the Interconnection System Impact Study). An Interconnection Customer with a CNR Interconnection Request that elected to waive the Interconnection Feasibility Study may also request that the Interconnection System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer’s Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection System Impact Study Agreement. The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis and any other analyses, such as electromagnetic transient analysis, that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner. The Interconnection System Impact Study report will state the assumptions upon

which it is based, state the results of the analyses, and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study report will provide (i) a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility, (ii) a non-binding good faith estimated time to construct, (iii) a protection assessment to determine the required protection upgrades; and may provide (iv) an evaluation of the siting of the Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.4.3, the Interconnection System Impact Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.4.4 Interconnection System Impact Study Procedures. The System Operator shall coordinate the Interconnection System Impact Study with the Interconnecting Transmission Owner, and with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, that is affected by the Interconnection Request. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection System Impact Study within forty-five (45) Business Days after the receipt of the Interconnection System Impact Study Agreement, study deposit, demonstration of Site Control, if Site Control is required, and required technical data in accordance with Section 3.4.2. If the System Operator uses Clustering, the System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within the times specified in this Section 3.4.4. At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the System Operator and Interconnecting Transmission Owner are unable to complete the Interconnection System Impact Study within the time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Except in the case of a CSIS, the System Operator shall notify the Interconnection Customer when the Interconnection System Impact Study is expected to commence within sixty-five (65) Calendar Days. An Interconnection Customer with an Interconnection Request being studied serially will be permitted to update the technical data provided in Attachment 2 of this SGIP and any attachments thereto, and submit modifications to that technical data to the System Operator no later than sixty (60) Calendar Days from the date that the System Operator notified the Interconnection Customer that the Interconnection System Impact Study is expected to commence. Such modifications will not be deemed Material Modifications unless the changes require a new Interconnection Request in accordance with Section 1.5.5 of this SGIP.

Where sufficient time has elapsed since the initial Scoping Meeting, within ten (10) Business Days after notifying the Interconnection Customer that the Interconnection System Impact Study is expected to commence, the System Operator may convene a second Scoping Meeting for the purpose of providing updated information to the Interconnection Customer in preparation for the submittal of updates to the technical data.

3.4.5 Meeting with Parties. Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, the System Operator shall convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, to discuss the results of the Interconnection System Impact Study. Within ten (10) Business Days following the study results meeting, the Interconnection Customer shall provide to the System Operator written notice that it will either pursue the Interconnection Facilities Study or waive the Interconnection Facilities Study and elect an expedited interconnection. Once the Interconnection Customer notifies the System Operator of its election, such election is not subject to change. If the Interconnection Customer elects to pursue the Facilities Study it must proceed with the study. If the Interconnection Customer waives the Facilities Study, it shall commit to the following milestones in the SGIA: (i) Siting approval for the Generating Facility and Interconnection Facilities; (ii) Engineering of Interconnection Facilities approved by Interconnecting Transmission Owner; (iii) Ordering of long lead time material for Interconnection Facilities and system upgrades; (iv) Initial Synchronization Date; and (v) Commercial Operation Date.

Within thirty (30) Calendar Days of the Interconnection Customer receiving the Interconnection System Impact Study report, the Interconnection Customer shall provide written comments on the report or written notice that it has no comments on the report. The System Operator shall issue a final Interconnection System Impact Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's notice that it will not provide comments.

3.4.6 Re-Study. If re-study of the Interconnection System Impact Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resources(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection System Impact Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection System Impact Study Agreement.

3.4.7 Operational Readiness. The System Operator shall, as close to the Interconnection Customer's actual Synchronization Date as reasonably possible, ensure that operational analysis, including current stability analyses, power flow analyses, and any other analyses deemed necessary by the System Operator, are performed, and that procedures are developed or updated to address the operation of the New England Transmission System with the addition of the Interconnection Customer's Generating Facility. The operational analysis will also include tests of system performance with selected facilities out of service. Such studies shall be performed at the expense of the Interconnection Customer. The System Operator is not obligated to perform the operational analyses described in this Section 3.4.7 if, in the exercise of reasonable discretion, the System Operator in consultation with Interconnecting Transmission Owner determines that interconnection of the Interconnection Customer's Generating Facility to the Administered Transmission System is remote and speculative.

3.5 Interconnection Facilities Study

3.5.1 Interconnection Facilities Study Agreement. Except as otherwise provided in Section 1.5.3.4 of this SGIP, the Interconnection Customer may waive the Interconnection Facilities Study and instead elect expedited interconnection and proceed with a SGIA in accordance with the requirements specified in Section 4.8. If the Interconnection Customer elects to proceed with an Interconnection Facilities Study, the System Operator shall provide to the Interconnection Customer an Interconnection Facilities Study Agreement in the form of Attachment 8 to this SGIP simultaneously with the delivery of the Interconnection System Impact Study report to the Interconnection Customer. The Interconnection Facilities Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection Facilities Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA. Within five (5) Business Days following the Interconnection Customer's Interconnection System Impact Study results meeting, the System Operator and Interconnecting Transmission Owner shall provide to the Interconnection Customer the Interconnection Facilities Study Agreement along with a non-binding good faith estimate of the cost to perform the Interconnection Facilities Study. The Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement, including completed attachments, to the System Operator within thirty (30) Business Days after its receipt, together with the required refundable deposit of the non-binding good faith estimated costs for the Interconnection Facilities Study. Any difference between the study deposit and the actual cost of the Interconnection Facilities Study shall be paid by or refunded to the Interconnection Customer. The System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the cost of the Interconnection Facilities Studies that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the Interconnection Facilities Study, the study agreement and its attachment(s) and the SGIA. In the case of Clustering, CFAC costs that are associated with an individual Interconnection Request assessed within the CFAC will be charged directly to that Interconnection Customer. CFAC costs that are associated with the CFAC as a whole will be divided equally, on a per-project basis, among the Interconnection Customers in the cluster. The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of

invoice. The System Operator shall continue to hold the amounts on deposits until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.5.2 Scope of Interconnection Facilities Study. The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Administered Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Interconnecting Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The scope and cost of the Interconnection Facilities Study shall include completion of any engineering work limited to what is reasonably required to (i) estimate such aforementioned cost, (ii) identify configurations of required facilities, and (iii) identify time requirements for construction and installation of required facilities. Design for any required Interconnection Facilities and/or Network Upgrades shall also be performed under the Interconnection Facilities Study. The Interconnection Customer, the System Operator, the Interconnecting Transmission Owner, and the Affected Party(ies), if any, may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design shall be reviewed and may be modified prior to acceptance by the Interconnecting Transmission Owner, under the provisions of the Interconnection Facilities Study Agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the System Operator and/or the Interconnecting Transmission Owner shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain any independent design and cost estimates for any necessary facilities.

3.5.3 Interconnection Facilities Study Procedures. The System Operator shall coordinate the Interconnection Facilities Study with Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. The System

Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the study and the System Operator shall issue a draft Interconnection Facilities Study report to the Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: forty-five (45) Business Days if upgrades are necessary, or thirty (30) Business Days if upgrades are not necessary. If the System Operator uses Clustering, the System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to deliver a completed Interconnection Facilities Study within the times specified in this Section 3.5.3.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Facilities Study, System Operator shall notify the Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, as to the schedule status of the Interconnection Facilities Study. If the System Operator is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, the System Operator shall notify the Interconnection Customer, Interconnecting Transmission Owner and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and provide an estimated completion date and an explanation of the reasons why additional time is required. The Interconnection Customer and appropriate Affected Parties may, within thirty (30) Business Days after receipt of the draft report, provide written comments to the System Operator and Interconnecting Transmission Owner, which the System Operator shall include in the final report. The System Operator shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The System Operator may reasonably extend such fifteen-day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the System Operator or Interconnecting Transmission Owner to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities report. Upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, or any third party consultant retained by the Interconnection Customer or to any non-market affiliate of the

Interconnection Customer supporting documentation, with workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study. The recipient(s) of such information shall be subject to the confidentiality provisions of this SGIP and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/ disclosure requirements, such information may be provided directly to the Interconnection Customer.

3.5.4 Meeting with Parties. Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, the System Operator will convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements to discuss the results of the Interconnection Facilities Study. Within thirty (30) Business Days of receipt of the study results, the Interconnection Customer shall provide written notice whether it agrees to pay for the Interconnection Facilities and upgrades identified in the Interconnection Facilities Study. An executable SGIA shall be tendered by the System Operator in conjunction with the Interconnecting Transmission Owner to the Interconnection Customer within five (5) Business Days of receipt of such agreement.

3.5.5 Re-Study. If re-study of the Interconnection Facilities Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project, (iii) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resource(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall so notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Facilities Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Facilities Study Agreement.

SECTION 4. PROVISIONS THAT APPLY TO ALL INTERCONNECTION REQUESTS

4.1 Reasonable Efforts

The System Operator and Interconnecting Transmission Owner shall make Reasonable Efforts to meet all time frames provided in these procedures unless the System Operator, the Interconnecting Transmission Owner and the Interconnection Customer agree to a different schedule. If the System Operator or Interconnecting Transmission Owner cannot meet a deadline provided herein, it shall notify the other Parties, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, the Party initiating the dispute resolution process shall provide the other Party(ies) with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two (2) Business Days after receipt of the Notice, any Party may contact the Commission's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for its own costs and its pro rata share of any costs paid to the neutral party and any associated common negotiating costs.

4.2.6 If none of the Parties elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then each Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Commission, state, or local regulatory requirements and with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards.

4.4.1 The System Operator and the Interconnecting Transmission Owner must be given at least five (5) Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5 Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party(ies) that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such. Confidential information shall include, without limitation, all information treated as confidential under the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the others prior to the execution of an SGIA.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party(ies) and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party(ies) as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if the Commission, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) prior to the release of the Confidential Information to the Commission. The Party shall notify the other Party(ies) when it is notified by the Commission that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The System Operator shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The System Operator and Interconnecting Transmission Owner shall use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Interconnecting Transmission Owner, its subsidiaries or affiliates, or others.

4.7 Record Retention

The System Operator shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 SGIA

In accordance with Section 3, the System Operator and the Interconnecting Transmission Owner shall tender to the Interconnection Customer a draft SGIA, together with draft attachments completed to the extent practicable. The Interconnection Customer shall return the Interconnection Customer specific information required to complete the form SGIA, including the attachments, within fifteen (15) Business Days. Within five (5) Business Days, the System Operator and the Interconnecting Transmission Owner shall issue a final draft of the SGIA to the Interconnection Customer.

The Interconnection Customer and the Interconnecting Transmission Owner shall have fifteen (15) Business Days or another mutually agreeable timeframe to sign three (3) originals of the SGIA and return them to the System Operator, who will send an original fully executed SGIA to Interconnecting Transmission Owner and Interconnection Customer, or the Interconnection Customer shall request that an unexecuted SGIA be filed with the Commission. If the Interconnection Customer does not sign the SGIA, or ask that it be filed unexecuted within thirty (30) Business Days after its receipt of the final draft of the SGIA, the Interconnection Request shall be deemed withdrawn. After the SGIA is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the SGIA.

The Interconnection Customer, the Interconnecting Transmission Owner and the System Operator shall be Parties to the SGIA.

Within fifteen (15) Business Days after receipt of the final SGIA, an Interconnection Customer with an Interconnection Request studied using Clustering that provided the additional Cluster Participation Deposit in accordance with Section 1.5.3.4.4 shall provide to the Interconnecting Transmission Owner, in cash, a potentially non-refundable deposit of twenty (20) percent of the total costs for the Interconnection Facilities and other upgrades, including any CETUs, identified in the CFAC, unless the Interconnecting Transmission Owner's expenditure schedule for the Interconnection Facilities and other upgrades calls for an initial payment of greater than twenty (20) percent of the total upgrade costs, in which case the scheduled initial payment must instead be made within the fifteenth Business Day after receipt of the final SGIA. If the Interconnection Customer does not submit this deposit (or make the initial payment) by the fifteenth Business Day after receipt of the final SGIA, the Interconnection Request shall be automatically withdrawn from the interconnection queue without further opportunity to cure, and the Interconnection Customer's initial and additional Cluster Participation Deposits shall become non-refundable. The non-

refundable initial and additional Cluster Participation Deposits shall be re-allocated, according to the cost allocation methodology contained in Schedule 11, to the Interconnection Customers with Interconnection Requests included in the cluster at the time the facilities proposed in the Interconnection Requests achieve Commercial Operation. If an Interconnection Request is withdrawn after the Interconnection Customer's payment of twenty (20) percent of the total cost responsibility for the upgrades to the Interconnecting Transmission Owner, then the payment shall be used to offset the costs of the CETU. Any unspent payments of the total cost responsibility for the upgrades to the Interconnecting Transmission Owner will be refunded to the respective Interconnection Customers that executed the Interconnection Agreement and provided to the Interconnecting Transmission Owner the twenty (20) percent deposit (or initial payment) if all the associated Interconnection Requests are withdrawn from the interconnection queue and the associated Interconnection Agreements are terminated.

4.9 Coordination with Affected Systems

The System Operator shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The System Operator will include such Affected System operators in all meetings held with the Interconnection Customer as required by the SGIP. The Interconnection Customer will cooperate with the System Operator and the Interconnecting Transmission Owner in all matters related to the conduct of studies and the determination of modifications to Affected Systems. The Interconnection Customer shall be responsible for the costs associated with the studies or portions of studies associated with the Affected Systems. Payment and refunds associated with the costs of such studies will be coordinated between the Interconnection Customer and the Affected Party(ies). The System Operator shall seek the cooperation of all Affected Parties in all matters related to the conduct of studies and the determination of modifications to Affected Systems. Nothing in the foregoing is intended to authorize the Interconnection Customer to receive interconnection, related facilities or other services on an Affected System, and provision of such services must be handled through separate arrangements with Affected Parties.

4.10 Evaluation of a Small Generating Facility Interconnection Request

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total energy capability or capacity capability of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System. However, if the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the System Operator's and Interconnecting Transmission Owner's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Administered Transmission System. If the System Operator and the Interconnecting Transmission Owner do not agree with the manner in which the Interconnection Customer proposes to implement the limit, then the Interconnection Request must be withdrawn or revised to specify the maximum energy capability and capacity capability that the Small Generating Facility is capable of injecting into the Administered Transmission System without such limitations. Furthermore, nothing in this section shall prevent the System Operator from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard (“CC Interconnection Standard”) – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource (“CNR”) – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability (“CNR Capability”) – The MW quantity associated with CNR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Capacity Network Resource Group Study (“CNR Group Study”) – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service (“CNR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer’s CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Cluster Enabling Transmission Upgrade (“CETU”) shall mean new significant transmission line infrastructure that consists of AC transmission lines and related terminal equipment having a nominal voltage rating at or above 115 kV or HVDC transmission lines and HVDC terminal equipment that is identified through the Clustering Enabling Transmission Upgrade Regional Planning Study conducted to accommodate the Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered. The CETU shall be considered part of a Generator Interconnection Related Upgrade and be categorized as Interconnection Facilities or Network Upgrades.

Cluster Enabling Transmission Upgrade Regional Planning Study (“CRPS”) shall mean a study conducted by the System Operator under Attachment K, Section II of the Tariff to identify the Cluster Enabling Transmission Upgrade and associated system upgrades to enable the interconnection of Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered.

Cluster Interconnection Facilities Study (“CFAC”) shall mean an Interconnection Facilities Study performed using Clustering pursuant to Section 1.5.3.4.

Cluster Interconnection System Impact Study (“CSIS”) shall mean an Interconnection System Impact Study performed using Clustering pursuant to Section 1.5.3.3.

Cluster Participation Deposit shall mean the initial and additional deposit due under Sections 1.5.3.3.2.2 and 1.5.3.4.4.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – For a unit, the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Standard Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner’s facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner’s Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Generating Facility – The Interconnection Customer’s device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities.

Initial Synchronization Date – The date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date – The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner’s Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner – A Transmission Owner that owns, leases or otherwise possesses an interest, or a Non-Incumbent Transmission Developer that is not a Participating Transmission Owner that is constructing, a portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Small Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner’s Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Attachment 2 to the Standard Small Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner’s Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer – Any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Small Generating Facility with the Administered Transmission System under the Standard Small Generator Interconnection Procedures.

Interconnection Customer’s Interconnection Facilities shall mean all facilities and equipment, as identified in Attachment 2 of the Standard Small Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer’s Interconnection Facilities are sole use facilities.

Interconnection Facilities – The Interconnecting Transmission Owner’s Interconnection Facilities and the Interconnection Customer’s Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study – A study conducted by the System Operator, Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner’s Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 3.5.2 of the Standard Small Generator Interconnection Procedures.

Interconnection Facilities Study Agreement – The form of agreement contained in Attachment 8 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study – A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 3.3 of the Standard Small Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection Feasibility Study Agreement – The form of agreement contained in Attachment 6 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request – The Interconnection Request shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP; (iv) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (v) commence participation in the wholesale markets by, an existing Generating Facility that is interconnected with the Administered Transmission System; or (vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service – The service provided by the System Operator and the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Small Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study – Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard

Small Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement – Any of the following agreements: The Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement attached to the Standard Small Generator Interconnection Procedures.

Interconnection System Impact Study – An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Small Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection System Impact Study Agreement – The form of agreement contained in Attachment 7 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Network Capability Interconnection Standard (“NC Interconnection Standard”) – The minimum criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Network Resource (“NR”) – The portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.

Network Resource Capability (“NR Capability”) – The MW quantity associated with NR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Network Resource Interconnection Service (“NR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Generating Facility to the Administered Transmission System in accordance with the Network Capability Interconnection Standard. An Interconnection Customer’s NR Interconnection Service shall be solely for the megawatt amount of the NR Capability. NR Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the New England Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Administered Transmission System to accommodate the interconnection with the Small Generating Facility to the Administered Transmission System. Network Upgrades do not include Distribution Upgrades.

Notice of Dispute – A written notice of a dispute or claim that arises out of or in connection with the Standard Small Generator Interconnection Agreement or its performance.

Party– The System Operator, Interconnecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Administered Transmission System.

Queue Position – The order of a valid request in the New England Control Area, relative to all other pending valid requests in the New England Control Area, that is established based upon the date and time of receipt of the valid Interconnection Request by the System Operator. Requests are comprised of interconnection requests for Generating Facilities, Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified

by the other electric systems, that impact the Administered Transmission System. References to a “higher-queued” Interconnection Request shall mean one that has been received by System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as “lower-queued.”

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the SGIP or SGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – A Generating Facility having a maximum gross capability at or above zero degrees F of 20 MW or less.

Stand Alone Network Upgrades – Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Attachment 2 to the Standard Small Generator Interconnection Agreement.

Study Case shall have the meaning specified in Sections 3.3.2 and 3.4.3 of this SGIP.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study.

Tariff - The System Operator’s or Affected System’s Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation – The period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Upgrades – The required additions and modifications to the Administered Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

**SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)**

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP Section 1.4, documentation of Site Control must be submitted with the Interconnection Request, except where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the proposed modifications do not require additional real property.

_____ Site Control is not provided because the proposed modification is to the Interconnection Customer's existing Small Generating Facility and, by checking this option, the Interconnection Customer certifies that it has Site Control and that the proposed modification does not require additional real property.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection that is subject to this SGIP must submit this Interconnection Request to the System Operator via the Interconnection Request Tracking Tool or IRTT, a web-based application for submitting, tracking and viewing Interconnection Requests available on the ISO New England website.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is \$4.50/kW (minimum of \$300 and maximum of \$7,500). The kW are the maximum gross kW of the Small Generating Facility. The Fast Track Process is limited to a Small Generating Facility that meets the eligibility requirements of section 2.1 and certain codes, standards and certification requirements.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the System Operator a non-refundable deposit of \$2,500 towards the cost of the scoping

meeting, the development of the interconnection study agreements, interconnection studies, and development of the SGIA. For Interconnection Requests that are identified for inclusion in a CRPS performed under Section 15 of Attachment K, Section II of the Tariff, the non-refundable deposit also shall be applied toward the costs incurred by the Interconnecting Transmission Owner in developing the cost estimates in support of the CRPS.

Interconnection Customer Information

Proposed Project Name: _____

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: _____

ISO Customer ID# (if available): _____

Contact Person: _____

Mailing Address: _____

City: _____ County: _____ State: _____ Zip: _____

Facility Location (if different from above): _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

- Application is for: _____ New Small Generating Facility
_____ Capacity addition to or modification of an existing Small Generating Facility
_____ Commencement of participation in the wholesale markets by an existing Small Generating Facility
_____ A change from Network Resource Interconnection Service to Capacity Network Resource Interconnection Service

If capacity addition to or modification of an existing facility, please describe: _____

If the capacity addition increases the maximum gross megawatt electrical output at an ambient temperature of 20 degrees F of the Generating Facility to more than 20 MW, the Interconnection Customer shall apply under Schedule 22.

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___ No ___

To Supply Power to Others? Yes ___ No ___

Is the Interconnection Request for:

Service Type (check one):

_____ Capacity Network Resource Interconnection Service (energy capability and capacity capability) or

_____ Network Resource Interconnection Service (energy capability only)

A retail customer interconnecting a new Small Generating Facility that will produce electric energy to be consumed only on the retail customer's site? Yes _____ No _____

A Qualifying Facility where 100% of the output will be sold to its host utility?
Yes _____ No _____

An Interconnection Customer interconnecting a new Small Generating Facility that plans to participate in the wholesale markets? Yes _____ No _____

An existing Small Generating Facility commencing participation in the wholesale markets?
Yes _____ No _____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

_____ (Local Electric Service Provider) _____ (Existing Account Number)

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Small Generating Facility Information

Interconnection Customer's Requested Initial Synchronization Date:

Interconnection Customer's Requested In-Service Date: _____

Interconnection Customer's Requested Commercial Operation Date: _____

Proposed Point of Interconnection: _____

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River): _____
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) _____

Prime Mover: ___ Fuel Cell ___ Recip Engine ___ Gas Turb ___ Steam Turb
___ Microturbine ___ PV ___ Other

Type of Generator: ___ Synchronous ___ Induction ___ Inverter

Generator Nameplate Rating: _____ kW (Typical) Generator Nameplate kVAR: _____

Interconnection Customer or Customer-Site Load: _____ kW (if none, so state)

Typical Reactive Load (if known): _____

Maximum Physical Export Capability Requested: _____ kW

Will the generator have energy storage capacity? Yes ___ No ___

If Yes, describe the energy storage device and specifications:

Provide the maximum output of each generator including each energy storage device: __

Primary frequency response operating range for electric storage resources:

Minimum State of Charge: _____

Maximum State of Charge: _____

Generating Facility Capacity (MW):

	Maximum Net MW Electrical Output	Maximum Gross MW Electrical Output
At 90 degrees F or higher		
At 50 degrees F or higher		
At 20 degrees F or higher		
At zero degrees F or higher		

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Is the prime mover compatible with the certified protective relay package? __ Yes __ No

Generator (or solar collector)

Manufacturer, Model Name & Number: _____

Version Number: _____

Nameplate Output Power Rating in kW: (Summer) _____ (Winter) _____

Nameplate Output Power Rating in kVA: (Summer) _____ (Winter) _____

Individual Generator Power Factor

Rated Power Factor: Leading: _____ Lagging: _____

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: _____ Elevation: _____ ___ Single phase ___ Three phase

Inverter Manufacturer, Model Name & Number (if used): _____

List of adjustable set points for the protective equipment or software: _____

Model Requirements

For all generation types: A completed, fully functioning, public (*i.e.*, non-proprietary or non-confidential) Siemens PTI's ("PSSE") power flow model or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flow ("PSLF") data sheet, must be supplied with this Interconnection Request. If additional public data sheets are more appropriate to the proposed device then they shall be provided and discussed at the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted.

A PSCAD model for all wind and inverter-based Small Generating Facilities must be supplied with this Interconnection Request. If a PSCAD model is deemed required for other Generating Facility types at the Scoping Meeting, such PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the executed Interconnection System Impact Study Agreement. A benchmarking analysis consistent with the requirements in the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model, shall be provided at the time the PSCAD model is submitted.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous ___ or RMS? _____

Harmonics Characteristics: _____

Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:

Generator AC resistance R_a : _____

Direct Axis Synchronous Reactance, X_d : _____ P.U.

Direct Axis Transient Reactance, X'_d : _____ P.U.

Direct Axis Subtransient Reactance, X''_d : _____ P.U.

Negative Sequence Reactance, X_2 : _____ P.U.

Zero Sequence Reactance, X_0 : _____ P.U.

KVA Base: _____

Field Volts: _____

Field Amperes: _____

Induction Generators:

Motoring Power (kW): _____

I_2^2t or K (Heating Time Constant): _____

Rotor Resistance, R_r : _____

Stator Resistance, R_s : _____

Stator Reactance, X_s : _____

Rotor Reactance, X_r : _____

Magnetizing Reactance, X_m : _____

Short Circuit Reactance, X_d'' : _____

Exciting Current: _____

Temperature Rise: _____

Frame Size: _____

Design Letter: _____

Reactive Power Required In Vars (No Load): _____

Reactive Power Required In Vars (Full Load): _____

Total Rotating Inertia, H: _____ Per Unit on kVA Base

Note: Please contact the System Operator prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___ Yes ___ No

Will the transformer be provided by the Interconnection Customer? ___ Yes ___ No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ___ single phase ___ three phase? Size: _____ kVA

Transformer Impedance: _____ % on _____ kVA Base

If Three Phase:

Transformer Primary: _____ Volts ___ Delta ___ Wye ___ Wye Grounded

Transformer Secondary: _____ Volts ___ Delta ___ Wye ___ Wye Grounded

Transformer Tertiary: _____ Volts ___ Delta ___ Wye ___ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _____ Type: _____ Size: _____ Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _____ Type: _____

Load Rating (Amps): _____ Interrupting Rating (Amps): _____ Trip Speed (Cycles): _____

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	_____	_____	_____
2.	_____	_____	_____
3.	_____	_____	_____
4.	_____	_____	_____
5.	_____	_____	_____
6.	_____	_____	_____

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting:

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Potential Transformer Data (If Applicable):

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

Manufacturer: _____

Type: _____ Accuracy Class: ___ Proposed Ratio Connection: _____

General Information

Enclose two copies of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Are two copies of One-Line Diagram Enclosed? ___ Yes ___ No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) _____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___ Yes ___ No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are Schematic Drawings Enclosed? ___ Yes ___ No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____ Date: _____

In order for a Small Generator Interconnection Request to be considered a valid request, it must:

- (a) Be accompanied by the applicable deposit that is provided electronically and which shall be non-refundable;
- (b) Include documentation of Site Control, if applicable;

- (c) Include a detailed map, such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures;
- (d) Include two copies, signed and stamped by a licensed Professional Engineer, of the site electrical one-line diagram; and
- (e) Include all information and data required on the Interconnection Request form and any attachments thereto.

The Interconnection Request must be submitted to the System Operator via the Interconnection Request Tracking Tool or IRTT.

Attachment A to Interconnection Request Form

SUPPLEMENTARY WIND AND INVERTER-BASED GENERATING FACILITY DATA FORM

1. Attach a Geographic Map Demonstrating the Project Layout and its Interconnection to the Power Grid. *(Specify the name of the attachment here)*

2. Attach a Bus-Breaker Based One-line Diagram (The diagram should include each of the individual wind unit, generator number, rating and terminal voltage.) *(Specify the name of the attachment here)*

2.1 Collection system detail impedance sheet

If a collector system is used, attach a collector system data sheet in accordance with the one-line diagram attached above. The data sheet should include: the type, length Z_0 , Z_1 and Xc/B of each circuit (feeder and collector string).

Specify the name of the attachment here: _____

2.2 Collection system aggregate (equivalent) model data sheet

Attach an aggregate (equivalent) collection system data sheet. The data table should include: the type, length, Z_0 , Z_1 and Xc/B of the equivalent circuits (feeders and collector strings).

Specify the name of the attachment here: _____

3. Summary of the Unit Models in the wind or inverter-based generating facility *(List all different unit models in the facility)*

Manufacturer Model	Type of this WTG* (if applicable)	Generator Unit Numbers in the field	Number(s) of these Units	Maximum Output of this Unit (MW)	Total MW

--	--	--	--	--	--

- * Type 1 – Cage rotor induction generators
- Type 2 – Induction generators with variable rotor resistance
- Type 3 – Doubly-fed asynchronous generators with rotor-side converter
- Type 4 – Full-power converter interface

Repeat the following sections from 4 to 12 for each different unit model.

4. Unit Detail Information

Unit Manufacturer Model	
Terminal Voltage	
Rating of Each Unit (MVA)	
Maximum Gross Electrical Output (MW)	
Minimum Gross Electrical Output(MW)	
Lagging Reactive Power Limit at Rated Real Power Output (MVAR)	
Leading Reactive Power Limit at Rated Real Power Output (MVAR)	
Lagging Reactive Power Limit at Zero Real Power Output (MVAR)	
Leading Reactive Power Limit at Zero Real Power Output (MVAR)	
Station Service Load(MW, MVAR)	
Minimum short circuit ratio(SCR) requirement by manufacturer	
On which bus the minimum SCR is required by manufacturer	
What voltage level the minimum SCR is required by manufacturer	
Positive sequence Xsource	
Zero sequence Xsource	

5. Unit GSU – _____

Nameplate rating (MVA)	
Total number of the GSUs	
Voltages, generator side/system side	
Winding connections, low voltage/high voltage	
Available tap positions on high voltage side	
Available tap positions on low voltage side	
Will the GSU operate as an LTC?	
Desired voltage control range if LTC	
Tap adjustment time (Tap switching delay + switching time) if LTC	
Desired tap position if applicable	
Impedance, Z1, X/R ratio	
Impedance, Z0, X/R ratio	

6. Low Voltage Ride Through(LVRT) – _____ (*Specify the Manufacturer Model of this Unit*)

Does each Unit have LVRT capability?

Yes__ No__

If yes, please provide:

6.1 Unit LVRT mode activation and release condition:

When operating at maximum real power, what is the Unit terminal voltage for LVRT mode activation? _____

When operating at maximum real power, what is the Unit terminal voltage for releasing LVRT mode after it is activated? _____

If there is different LVRT activation and release logic, please state here _____

6.2 A wind or inverter-based generating facility technical manual from the manufacturer including description of LVRT functionality:

Attach the file and specify the name of the attachment here:

6.3 Does the wind or inverter-based generating facility technical manual attached above include a reactive power capability curve?

Yes__ No__

If no, attach the file and specify the name of the attachment here:

7. Low Voltage Protection (considering LVRT functionality)

(Specify the Manufacturer Model of this Unit)

Low Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

8. High Voltage Protection - _____ (Specify the Manufacturer Model of this Unit)

High Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

9. Low Frequency Protection - _____ (Specify the Manufacturer Model of this Unit)

Low Frequency Setting (Hz)	Relay Pickup Time (Seconds)

--	--

*Add more rows in the table as needed

10. High Frequency Protection - _____ (Specify the Manufacturer Model of this Unit)

High Frequency Setting (Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

Please make sure the settings in sections 7 through 10 comply with NERC and NPCC standards for generator protection relays.

11. Unit Reactive Power Control - _____ (Specify the Manufacturer Model of this Unit)

11.1 What are the options for the Unit reactive power control (check all available)?

- ____ Control the voltage at the Unit terminal
- ____ Control constant power factor at the Unit terminal
- ____ Control constant power factor at the low side of the station main transformer
- ____ Control constant power factor at the high side of the station main transformer
- ____ Control voltage at the low side of the station main transformer
- ____ Control voltage at the high side of the station main transformer
- ____ Other options. Please describe if select others

11.2 In all the control options selected above, please list the options in which the Unit is able to control its terminal voltage to prevent low/high voltage tripping.

11.3 What is the desired control mode from the selected options above? Specify the control plan in this mode. For example: control voltage at which bus to what schedule.

12. Wind or inverter-based generating facility Model

(All model files provided under this section 12 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

12.1 Power flow model

12.1.1 A *.RAW file including **aggregated/equivalent** wind or inverter-based generating facility power flow model with appropriate parameters and settings.

*Attach the *.RAW file and specify the name of the attachment here:*

12.1.2 A *.RAW file including **detailed** wind or inverter-based generating facility power flow model with appropriate parameters and settings. *(Optional)*

*Attach the *.RAW file and specify the name of the attachment here:*

12.2 Dynamic simulation model

(Please note that the dynamic model must match the aggregated/equivalent power flow model provided above. Attach the following information for each of the models.)

12.2.1 Wind or inverter-based generating facility Model _____ (Please Specify the Manufacturer Model)

12.2.2 A compiled PSS/E dynamic model for the turbines (a *.LIB or *.OBJ file)

*Attach the *.LIB or *.OBJ file and specify the name of the attachment here:*

12.2.3 A dynamic data file with appropriate parameters and settings for the turbines (typically a *.DYZ file)

*Attach the *.DYZ file and specify the name of the attachment here:*

12.2.4 PSS/E wind or inverter-based generating facility model user manual for the WTG

Attach and specify the name of the attachment here:

Repeat the above sections from 6 to 12 for each different wind or inverter-based generating facility model.

13. Power Plant Controller

Will the wind or inverter-based generating facility be equipped with power plant controller, which has the ability to centrally control the output of the units?

Yes__ No__

If yes, please provide:

13.1 Manufacturer model of the power plant controller

13.2 What are the reactive power control strategy options of the power plant controller?

13.3 Which of the control option stated above is being used in current operation?

13.3 Is the power plant controller able to control the unit terminal voltages to prevent low/high voltage tripping?

Yes__ No__

Please provide the park controller technical manual from the manufacturer

Attach the file and specify the name of the attachment here:

14. Station Transformer

Transformer Name		
Nameplate ratings (MVA)		
Total number of the main transformer(s)		
Voltages, High/Low/Tertiary (kV)		
Winding connections, High/Low/Tertiary		
Available tap positions on high voltage side		
Available tap positions on low voltage side		
Will the transformer operate as a LTC?		
Desired voltage control range if LTC		
Tap adjustment time (Tap switching delay + switching time) if LTC		
Desired tap position if applicable		
Tap adjustment time (Tap switching delay + switching time)		
Impedance Z_1 , X/R ratio	Z_{1H-L}	X/R
	Z_{1H-T}	X/R
	Z_{1T-L}	X/R
Impedance Z_0 , X/R ratio	Z_{0H-L}	X/R
	Z_{0H-T}	X/R
	Z_{0T-L}	X/R

15. Dynamic Simulation Model for the Power Plant Controller(s) (if applicable)

(All model files provided under this section 15 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

15.1 A compiled PSS/E dynamic model for the power plant controller(s) (a *.LIB or *.OBJ file)

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

- 15.2 A dynamic data file with appropriate parameters and settings for the power plant controller(s) (typically a *.DYR file).

Please set the parameters in accordance with the currently used control mode.

*Attach the *.DYR file and specify the name of the attachment here:*

- 15.3 PSS/E model user manual for the power plant controller(s)

*Attach the manual and specify the name of the attachment or specify the name of the attachment here:*_____

16. Capacitors and Reactors

Please provide necessary modeling data for all the capacitors and reactors belong to the facility, including: size, basic electrical parameters, connecting bus, switched or fixed, etc.

17. Dynamic Device(s)

(All model files provided under this section 17 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

- 17.1 Provide necessary modeling data file for all the dynamic devices belong to the facility.

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

- 17.2 A dynamic data file containing the parameters for the units (typically a *.DYR file).

Set the parameters in accordance with the desired control mode.

Attach the *.DYR file and specify the name of the attachment here:

18. Collection System/Transformer Tap-Setting Design

Attach a collection system/transformer tap-setting design calculations, consistent with the requirements in the ISO New England Planning Procedures, that identify the calculations to

support the proposed tap settings for the unit step-up transformers and the station step-up transformers.

Attach the design document and specify the name of the attachment here:

19. Additional Information

Are there any special features available to be implemented to the wind or inverter-based generating facility? Such as weak grid interconnection solutions, etc.

Specify the available features here:

Insert the technical manual for each of the features listed above as objects (display as icons) or specify the name of the attachment

here:

20. Provide PSCAD Model and Documentation for the wind or inverter-based generating facility, the Power Plant Controller(s) and Other Dynamic Devices for the wind or inverter-based generating facility.

ISO will determine how much PSCAD work is needed from the wind or inverter-based generating facility based on its interconnection system conditions.

CLUSTER SYSTEM IMPACT STUDY APPLICATION FORM

The undersigned Interconnection Customer submits this form to request the inclusion of the Interconnection Request for its Small Generating Facility in a Cluster Interconnection System Impact Study pursuant to Section 1.5.3.3.2.2 of this SGIP.

To be included in a Cluster Interconnection System Impact Study, the following must be submitted together with this form to the System Operator by the Cluster Entry Deadline:

1. Project Information:

a. Project Name: _____

b. Queue Position: _____

c. Is the Interconnection Request contractually associated with another Interconnection Request for an Elective Transmission Upgrade? Yes ____ No ____

If yes, identify Queue Position of the associated Interconnection Request and provide evidence of the contractual commitment. Queue Position No.: _____

2. Initial Cluster Participation Deposit as specified in Section 1.5.3.3.2.2.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this form is true and accurate.

For Interconnection Customer: _____ Date: _____

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Certification of Small Generator Equipment Packages

- 1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.
- 2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
- 3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.
- 4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

- 5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.
- 6.0 An equipment package does not include equipment provided by the utility.
- 7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

10 kW Inverter Process

Solely applicable for Network Resource Interconnection Service

- 1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the System Operator.
- 2.0 The System Operator acknowledges to the Customer receipt of the Application within three Business Days of receipt.
- 3.0 The System Operator in conjunction with the Interconnecting Transmission Owner evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.
- 4.0 The System Operator in conjunction with the Interconnecting Transmission Owner verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The System Operator has 15 Business Days to complete this process. Unless the System Operator in conjunction with the Interconnecting Transmission Owner determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the System Operator approves the Application and returns it to the Customer. Note to Customer: Please check with the System Operator before submitting the Application if disconnection equipment is required.
- 5.0 After installation, the Customer returns the Certificate of Completion to the System Operator. Prior to parallel operation, the System Operator and Interconnecting Transmission Owner may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.
- 6.0 The System Operator in conjunction with the Interconnecting Transmission Owner notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Interconnecting Transmission Owner has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Interconnecting Transmission Owner is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Interconnecting Transmission Owner does not

inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

- 7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the System Operator and the Interconnecting Transmission Owner, that contact information must be provided on the Application.
- 8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.
- 9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.4, documentation of Site Control must be submitted with the Interconnection Request, except where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of \$100 must accompany this Application.

Interconnection Customer

Name: _____

Contact Person: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Contact (if different from Interconnection Customer)

Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Owner of the facility (include % ownership by any electric utility): _____

Small Generating Facility Information

Location (if different from above): _____

Electric Service Company: _____

Account Number: _____

Is the Interconnection Request for:

A retail customer interconnecting a new Small Generating Facility that will produce electric energy to be consumed only on the retail customer’s site? Yes ____ No ____

A Qualifying Facility where 100% of the output will be sold to its host utility?
Yes ____ No ____

An Interconnection Customer interconnecting a new Small Generating Facility that plans to participate in the wholesale markets? Yes ____ No ____

An existing Small Generating Facility commencing participation in the wholesale markets?
Yes ____ No ____

Inverter Manufacturer: _____ Model _____

Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)

Single Phase _____ Three Phase _____

System Design Capacity: _____ (kW) _____ (kVA)

Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell

Turbine Other _____

Energy Source: Solar Wind Hydro Diesel Natural Gas

Fuel Oil Other (describe) _____

Is the equipment UL1741 Listed? Yes ____ No ____

If Yes, attach manufacturer’s cut-sheet showing UL1741 listing

Estimated Installation Date: _____ Estimated In-Service Date: _____

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small

Generator Interconnection Procedures (SGIP), or the Interconnecting Transmission Owner has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: _____

Title: _____ Date: _____

**Contingent Approval to Interconnect the Small Generating Facility
(For Internal use only)**

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Interconnecting Transmission Owner Signature: _____

Title: _____ Date: _____

Application ID number: _____

Interconnecting Transmission Owner waives inspection/witness test? Yes ___ No ___

System Operator Signature: _____

Title: _____ Date: _____

Application ID number: _____

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes _____ No _____

Interconnection Customer: _____

Contact Person: _____

Address: _____

Location of the Small Generating Facility (if different from above):

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Electrician:

Name: _____

Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

License number: _____

Date Approval to Install Facility granted by the Interconnecting Transmission Owner: _____

Application ID number: _____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local building/electrical code of _____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Print Name: _____

Date: _____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert System Operator and Interconnecting Transmission Owner information below):

Name: _____

System Operator: _____

Address: _____

City, State ZIP: _____

Fax: _____

Name: _____

Interconnecting Transmission Owner:

Address: _____

City, State ZIP: _____

Fax: _____

Approval to Energize the Small Generating Facility

(For Internal use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Interconnecting Transmission Owner Signature: _____

Title: _____ Date: _____

System Operator Signature: _____

Title: _____ Date: _____

**Terms and Conditions for Interconnecting an Inverter-Based
Small Generating Facility No Larger than 10kW**

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the System Operator approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Interconnecting Transmission Owner's (the "Company") electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the System Operator and the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small

Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 **Insurance**

The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

9.1 By the Customer

9.2 By providing written notice to the Company and the System Operator.

9.3 By the Company or the System Operator

9.4 If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

10.0 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

11.0 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require any Party to fulfill rights or obligations that arose under the Agreement.

12. **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the System Operator and the Company.

Interconnection Feasibility Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and _____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on _____; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Administered Transmission System; and

WHEREAS, Interconnection Customer has requested the System Operator and Interconnecting Transmission Owner to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility with the facilities that are part of the Interconnecting Transmission Owner's Administered Transmission System, and of any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures ("SGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection Feasibility Study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.
- 4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the Interconnection Feasibility Study may be extended by agreement of the Parties.
- 5.0 In performing the study, the System Operator and Interconnecting Transmission Owner shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the Interconnection Feasibility Study.
- 6.0 The Interconnection Feasibility Study report shall provide the following analyses depending on whether the Feasibility Study consisted of: (a) a power flow, including thermal analysis and voltage analysis, and short circulated analysis, or (b) limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the interconnection of the Small Generating Facility as proposed given recent study experience and as discussed at the Scoping Meeting:
 - 6.1 Initial identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection, or, findings of the limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient

analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;

- 6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;
 - 6.3 Preliminary description of and a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study;
 - 6.4 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, initial review of grounding requirements and electric system protection;
 - 6.5 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues and length of time that would be necessary to construct the facilities; and
 - 6.6 To the extent the Interconnection Customer requested a preliminary analysis as described in Section 3.3.2 of the SGIP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.
- 7.0 The Interconnection Feasibility Study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

- 8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.
- 9.0 A deposit, paid to the System Operator, of the lesser of 50 percent of good faith estimated Interconnection Feasibility Study costs or earnest money of \$1,000 shall be required from the Interconnection Customer.
- 10.0 Once the Interconnection Feasibility Study is completed, an Interconnection Feasibility Study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the Interconnection Feasibility Study must be completed and the Interconnection Feasibility Study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct an Interconnection Feasibility Study.
- 11.0 The total estimated cost of the performance of the Interconnection Feasibility Study consists of \$ [insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted. 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator shall refund such excess within 30 calendar days of the invoice without interest.
- 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator shall refund such excess within 30 calendar days of the invoice without interest
- 13.0 Miscellaneous.
- 13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Feasibility Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection Feasibility Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection Feasibility Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection Feasibility Study, the content of the Interconnection Feasibility Study, or the conclusions of the Interconnection Feasibility Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

13.3 Force Majeure, Liability and Indemnification.

13.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

13.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System

Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

- 13.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case

of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 13.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 13.2 and 13.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection Feasibility Study shall not be deemed third party beneficiaries of Sections 13.2 and 13.3.
- 13.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 13.5, shall continue in effect for a term of one year or until the Interconnection Feasibility Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.

- 13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.
- 13.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 13.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 13.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 13.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 13.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other

failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

- 13.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.
- 13.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 13.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 13.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the

hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

13.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

13.16 Reservation of Rights. Subject to the TOA, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator]

[Insert name of Interconnection Customer]

Signed _____

Name (Printed):

Title _____

Signed _____

Name (Printed):

Title _____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to
Interconnection Feasibility Study Agreement**

Assumptions Used in Conducting the Interconnection Feasibility Study

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on _____:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer, System Operator and Interconnecting Transmission Owner.

Interconnection System Impact Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and
_____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
Administered Transmission System;

WHEREAS, the System Operator and Interconnecting Transmission Owner have completed an
Interconnection Feasibility Study and provided the results of said study to the Interconnection Customer
(This recital to be omitted if the Parties have agreed to forego the Interconnection Feasibility Study.); and

WHEREAS, the Interconnection Customer has requested the System Operator and Interconnecting
Transmission Owner to perform an Interconnection System Impact Study(s) to assess the impact of
interconnecting the Small Generating Facility with the facilities that are part of the Interconnecting
Transmission Owner's Administered Transmission System, and of any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

- 1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.
- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection System Impact Study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of an Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.
- 4.0 An Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request. The System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.
- 5.0 An Interconnection System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. An Interconnection System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. An Interconnection System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and

time to construct.

- 6.0 A distribution Interconnection System Impact Study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.
- 7.0 Affected Systems may participate in the preparation of an Interconnection System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon an Interconnection System Impact Study that covers potential adverse system impacts on their electric systems, and the System Operator and Interconnecting Transmission Owner have 20 additional Business Days to complete an Interconnection System Impact Study requiring review by Affected Systems.
- 8.0 If the System Operator uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the Interconnection System Impact Study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced.
- 8.1 Are directly interconnected with the Administered Transmission System; or
- 8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and
- 8.3 Have a pending higher queued Interconnection Request to interconnect with the Administered Transmission System.
- 9.0 A distribution Interconnection System Impact Study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission Interconnection System Impact Study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties.

- 10.0 A deposit of the equivalent of the good faith estimated cost of a distribution Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer; and the one half the good faith estimated cost of a transmission Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer.
- 11.0 The total estimated cost of the performance of the Interconnection System Impact Study consists of \$[insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.
- 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator or Interconnecting Transmission Owner, as applicable, shall refund such excess within 30 calendar days of the invoice without interest.
- 13.0 Miscellaneous.
- 13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.
- 13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection System Impact Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection System Impact Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection System Impact Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied,

whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection System Impact Study, the content of the Interconnection System Impact Study, or the conclusions of the Interconnection System Impact Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

13.3 Force Majeure, Liability and Indemnification.

13.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

13.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission

Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

13.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of

Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 13.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 13.2 and 13.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection System Impact Study shall not be deemed third party beneficiaries of Sections 13.2 and 13.3.
- 13.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 13.5, shall continue in effect for a term of one year or until the Interconnection System Impact Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.
- 13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be

deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.

- 13.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 13.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 13.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 13.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 13.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.
- 13.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the

Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.

- 13.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 13.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 13.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.
- 13.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.
- 13.16 Reservation of Rights. Subject to the TO Agreement, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any

other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator] [Insert name of Interconnection Customer]

Signed _____

Name (Printed):

Title _____

Signed _____

Name (Printed):

Title _____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to System
Impact Study Agreement**

Assumptions Used in Conducting the System Impact Study

The Interconnection System Impact Study shall be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer, System Operator and Interconnecting Transmission Owner.

Interconnection Facilities Study Agreement

THIS AGREEMENT is made and entered into this ____ day of _____
20__ by and between _____,
a _____ organized and existing under the laws of the State of
_____, ("Interconnection Customer,") and ISO New
England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System
Operator"), and
_____, a _____
existing under the laws of the State of _____,
("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and
Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
Administered Transmission System;

WHEREAS, the System Operator and Interconnecting Transmission Owner have completed an
Interconnection System Impact Study and provided the results of said study to the Interconnection
Customer; and

WHEREAS, the Interconnection Customer has requested the System Operator and Interconnecting
Transmission Owner to perform an Interconnection Facilities Study to specify and estimate the cost of the
equipment, engineering, procurement and construction work needed to implement the conclusions of the
Interconnection System Impact Study in accordance with Good Utility Practice to physically and
electrically connect the Small Generating Facility with the facilities that are part of the Interconnecting
Transmission Owner's Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

- 1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures, or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”).
- 2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause an Interconnection Facilities Study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.
- 3.0 The scope of the Interconnection Facilities Study shall be subject to data provided in Attachment A to this Agreement.
- 4.0 The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the Interconnection System Impact Study(s). The Interconnection Facilities Study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Interconnecting Transmission Owner’s Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.
- 5.0 The System Operator and Interconnecting Transmission Owner may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.
- 6.0 A deposit, paid to the System Operator, of the good faith estimated Interconnection Facilities Study costs shall be required from the Interconnection Customer.
- 7.0 In cases where Upgrades are required, the Interconnection Facilities Study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are

necessary, and the required facilities are limited to Interconnection Facilities, the Interconnection Facilities Study must be completed within 30 Business Days.

- 8.0 Once the Interconnection Facilities Study is completed, an Interconnection Facilities Study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the Interconnection Facilities Study must be completed and the Interconnection Facilities Study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct an Interconnection Facilities Study.
- 9.0 The total estimated cost of the performance of the Interconnection Facility Study consists of \$ [insert], which is comprised of the System Operator's cost of \$[insert] and the Interconnecting Transmission Owner's cost of \$[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.
- 10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator or Interconnecting Transmission Owner, as applicable, shall refund such excess within 30 calendar days of the invoice without interest.
- 11.0 Miscellaneous.
- 11.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.
- 11.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Facilities Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly,

beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection Facilities Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection Facilities Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the information considered in conducting the Interconnection Facilities Study, the content of the Interconnection Facilities Study, or the conclusions of the Interconnection Facilities Study. Interconnection Customer acknowledges that it has not relied on any representations or warranties not specifically set forth herein and that no such representations or warranties have formed the basis of its bargain hereunder.

11.2 Force Majeure, Liability and Indemnification.

11.3.1 Force Majeure. Neither System Operator, Interconnecting Transmission Owner nor an Interconnection Customer will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure affecting any entity shall excuse that entity from making any payment that it is obligated to make hereunder. However, an entity whose performance under this Agreement is hindered by an event of Force Majeure shall make all Reasonable Efforts to perform its obligations under this Agreement, and shall promptly notify the System Operator, the Interconnecting Transmission Owner or the Interconnection Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

11.3.2 Liability. System Operator shall not be liable for money damages or other compensation to the Interconnection Customer for action or omissions by System Operator in performing its obligations under this Agreement, except to the extent such act or omission by System Operator is found to result from its gross negligence or willful misconduct. Interconnecting Transmission Owner shall not be liable for money damages or other compensation to the Interconnection

Customer for action or omissions by Interconnecting Transmission Owner in performing its obligations under this Agreement, except to the extent such act or omission by Interconnecting Transmission Owner is found to result from its gross negligence or willful misconduct. To the extent the Interconnection Customer has claims against System Operator or Interconnecting Transmission Owner, the Interconnection Customer may only look to the assets of System Operator or Interconnecting Transmission Owner (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either who, the Interconnection Customer acknowledges and agrees, have no personal or other liability for obligations of System Operator or Interconnecting Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of System Operator or Interconnecting Transmission Owner or Affiliate of either. In no event shall System Operator, Interconnecting Transmission Owner or Interconnection Customer be liable 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 under this Agreement. Notwithstanding the foregoing, nothing in this section shall diminish an Interconnection Customer's obligations under the Indemnification section below.

- 11.3.3 Indemnification. Interconnection Customer shall at all times indemnify, defend, and save harmless System Operator and the Interconnecting Transmission Owner and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities ("Losses") by or to third parties arising out of or resulting from the performance by System Operator or Interconnecting Transmission Owner under this Agreement, any bankruptcy filings made by the Interconnection Customer, or the actions or omissions of the Interconnection Customer in connection with this Agreement, except in the case of System Operator, to the extent such Losses arise from the gross negligence or willful misconduct by System Operator or its directors, officers, members, employees or agents, and, in the case of Interconnecting Transmission Owner, to the extent such Losses arise from the gross negligence or willful misconduct by

Interconnecting Transmission Owner or its directors, officers, members, employees or agents. The amount of any indemnity payment hereunder shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified party in respect of the indemnified action, claim, demand, cost, damage or liability. The obligations of Interconnection Customer to indemnify System Operator and Interconnecting Transmission Owner shall be several, and not joint or joint and several. The liability provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner.

- 11.4 Third-Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns. Notwithstanding the foregoing, and without limitation of Sections 11.2 and 11.3 of this Agreement, the Parties agree that subcontractor consultants hired by them to conduct, participate in, or review, or to assist in the conducting, participating in, or reviewing of, an Interconnection Facilities Study shall not be deemed third party beneficiaries of Sections 11.2 and 11.3.
- 11.5 Term and Termination. This Agreement shall be effective from the date hereof and unless earlier terminated in accordance with this Section 11.5, shall continue in effect for a term of one year or until the Interconnection Facilities Study is completed. This Agreement shall automatically terminate upon the withdrawal of Interconnection Request under Section 1.8 of the SGIP. The System Operator or the Interconnecting Transmission Owner may terminate this Agreement fifteen (15) days after providing written notice to the Interconnection Customer that it has breached one of its obligations hereunder, if the breach has not been cured within such fifteen (15) day period.
- 11.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek

changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

- 11.7 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority: (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.
- 11.8 Counterparts. This Agreement may be executed in counterparts, and each counterpart shall have the same force and effect as the original instrument.
- 11.9 Amendment. No amendment, modification or waiver of any term hereof shall be effective unless set forth in writing and signed by the Parties hereto.
- 11.10 Survival. All warranties, limitations of liability and confidentiality provisions provided herein shall survive the expiration or termination hereof.
- 11.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.
- 11.12 No Implied Waivers. The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to insist or rely on any such provision, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect. Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an

interconnection from the System Operator and the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

- 11.13 Successors and Assigns. This Agreement may not be assigned, by operation of law or otherwise, without the prior written consent of the other Parties hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing, this Agreement, and each and every term and condition hereof, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns, to the extent the same are authorized hereunder.
- 11.14 Due Authorization. Each Party to this Agreement represents and warrants that it has full power and authority to enter into this Agreement and to perform its obligations hereunder, that execution of this Agreement will not violate any other agreement with a third party, and that the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.
- 11.15 Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.
- 11.15.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the System Operator or Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

11.15.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

11.16 Reservation of Rights. Subject to the TOA, the System Operator and the Interconnecting Transmission Owner shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of System Operator] **[Insert name of Interconnection Customer]**

_____	_____
Signed _____	Signed _____
Name (Printed):	Name (Printed):
_____	_____
Title _____	Title _____

[Insert name of Interconnecting Transmission Owner]

Signed _____

Name (Printed):

Title _____

**Attachment A to
Interconnection Facilities Study Agreement**

**Data to Be Provided by the Interconnection Customer
with the Interconnection Facilities Study Agreement**

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location.
(Maximum load on Current Transformer/Power Transformer (“CT/PT”))

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT)
Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: _____

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes ____ No _____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes _____ No _____
(Please indicate on the one-line diagram).

What type of control system or Power Line Carrier (“PLC”) will be located at the Small Generating Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Administered Transmission System.

Tower number observed in the field. (Painted on tower leg)*:

Number of third party easements required for transmission lines*:

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?

Yes _____ No _____ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction Date: _____

Generator step-up transformers
receive back feed power Date: _____

Generation Testing Date: _____

Commercial Operation Date: _____

**STANDARD SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)**

TABLE OF CONTENTS

Article. 1. Scope and Limitations of Agreement

- 1.1 Applicability
- 1.2 Purpose
- 1.3 No Agreement to Purchase or Deliver Power
- 1.4 Limitations
- 1.5 Responsibilities of the Parties
- 1.6 Parallel Operation Obligations
- 1.7 Metering
- 1.8 Reactive Power and Primary Frequency Response
- 1.9 Capitalized Term
- 1.10 Scope of Service

Article. 2. Inspection, Testing, Authorization, and Right of Access

- 2.1 Equipment Testing and Inspection
- 2.2 Authorization Required Prior to Parallel Operation
- 2.3 Right of Access

Article. 3. Effective Date, Term, Termination, and Disconnection

- 3.1 Effective Date
- 3.2 Term of Agreement
- 3.3 Termination
- 3.4 Temporary Disconnection
 - 3.4.1 Emergency Conditions
 - 3.4.2 Routine Maintenance, Construction, and Repair
 - 3.4.3 Forced Outages
 - 3.4.4 Adverse Operating Effects
 - 3.4.5 Modification of the Small Generating Facility
 - 3.4.6 Reconnection

Article. 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

- 4.1 Interconnection Facilities
- 4.2 Distribution Upgrades

Article. 5. Cost Responsibility for Network Upgrades

- 5.1 Applicability

- 5.2 Network Upgrades
- 5.3 Special Provisions for Affected Systems
- 5.4 Rights Under Other Agreements

Article.6. Billing, Payment, Milestones, and Financial Security

- 6.1 Billing and Payment Procedures and Final Accounting
- 6.2 Milestones
- 6.3 Financial Security Arrangements

Article. 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

- 7.1 Assignment
- 7.2 Limitation of Liability
- 7.3 Indemnity
- 7.4 Consequential Damages
- 7.5 Force Majeure
- 7.6 Default

Article. 8. Insurance Requirements

- 8.1 General Liability
- 8.2 Insurer Requirements and Endorsements
- 8.3 Evidence of Insurance
- 8.4 Self Insurance
- 8.5 Interconnecting Transmission Owner Insurance

Article. 9. Confidentiality

Article. 10. Disputes

Article. 11. Taxes

Article. 12. Miscellaneous

- 12.1 Governing Law, Regulatory Authority, and Rules
- 12.2 Amendment
- 12.3 No Third-Party Beneficiaries
- 12.4 Waiver
- 12.5 Entire Agreement
- 12.6 Multiple Counterparts
- 12.7 No Partnership
- 12.8 Severability
- 12.9 Security Arrangements

12.10 Environmental Releases

12.11 Subcontractors

12.12 Reservation of Rights

Article. 13. Notices

13.1 General

13.2 Billing and Payment

13.3 Alternative Forms of Notice

13.4 Designated Operating Representative

13.5 Changes to the Notice Information

Article. 14. Signatures

Attachments to SGIA

Attachment 1 – Glossary of Terms

Attachment 2 – Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Attachment 3 – One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4 – Milestones

Attachment 5 – Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer’s Needs

Attachment 6 – Interconnecting Transmission Owner’s Description of its Upgrades and Best Estimate of Upgrade Costs

Attachment 7 – Commercial Operation Date

THIS STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT ("Agreement")

is made and entered into this _____ day of _____, 20__, by and between _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ (“Interconnection Customer” with a Small Generating Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware (“System Operator”), and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ (“Interconnecting Transmission Owner”). Under this Agreement the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a “Party” or collectively as the “Parties.”

In consideration of the mutual covenants set forth herein, the Parties agree as follows

Article 1. Scope and Limitations of Agreement

1.1 Applicability:

This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 Purpose

This Agreement governs the terms and conditions under which the Interconnection Customer’s Small Generating Facility will interconnect with, and operate in parallel with, the Interconnecting Transmission Owner’s facilities that are part of the Administered Transmission System.

1.3 No Agreement to Purchase or Deliver Power

This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Party.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement between the Parties.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Interconnecting Transmission Owner shall construct, operate, and maintain its transmission facilities and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their

respective sides of the point of change of ownership. The Interconnecting Transmission Owner and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the New England Transmission System [or Interconnecting Transmission Owner's transmission facilities], personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

- 1.5.6 The System Operator, with input from the Interconnecting Transmission Owner, shall coordinate with all Affected Systems to support the interconnection.
- 1.5.7 The Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 2.1 of this Agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The Small Generating Facility's protective equipment settings shall comply with the Interconnecting Transmission Owner's automatic load-shed program. The System Operator and Interconnecting Transmission Owner shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The term “frequency ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting

Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis. The term “voltage ride through” as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Interconnecting Transmission Owner, the New England Transmission System and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the New England Control Area on a comparable basis.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to the ISO New England Operating Documents, and the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Interconnecting Transmission Owner’s reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachment 2 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power and Primary Frequency Response

1.8.1 Power Factor Design Criteria

1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection with dynamic reactive capability over the power factor range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all similarly situated synchronous (and non-wind non-synchronous generators as specified in Appendix G, Section A.ii.4, to the LGIA) generators on a comparable basis and in accordance with Operating Requirements.

1.8.1.2 Non-Synchronous Generation. Generating Facilities shall be subject to the power factor design criteria specified in Appendix G to the LGIA. Wind and inverter-based Generating Facilities shall be subject to the Low Voltage Ride-Through Capability requirements specified in Appendix G to the LGIA.

1.8.2 Interconnection Customers shall be compensated for reactive power service in accordance with Schedule 2 of the Tariff.

1.8.3 Primary Frequency Response

Interconnection Customer with an Interconnection System Impact Study that commenced before May 15, 2018 is obligated to provide and maintain a functioning governor on all generating units comprising the Small Generating Facility in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnection Customer with an Interconnection System Impact Study that commenced on or after May 15, 2018 shall ensure the primary frequency response capability of its Small Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility’s real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a

maximum 5 percent droop and ± 0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based on an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Small Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify System Operator and Interconnecting Transmission Owner that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the New England Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Articles 1.8.3.1 and 1.8.3.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities.

1.8.3.1 Governor or Equivalent Controls. Whenever the Small Generating Facility is operated in parallel with the New England Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with System Operator and Interconnecting Transmission Owner, set the deadband parameter to: (1) a maximum of ± 0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability

Standard that provides for equivalent or more stringent parameters.

Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to System Operator and Interconnecting Transmission Owner upon request. If Interconnection Customer needs to operate the Small Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify System Operator and Interconnecting Transmission Owner, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Small Generating Facility's governor or equivalent controls to a minimum whenever the Small Generating Facility is operated in parallel with the New England Transmission System.

1.8.3.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Small Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

1.8.3.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Articles 1.8.3, 1.8.3.1, and 1.8.3.2 of this Agreement. Small Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Article 1.8.3, but shall be otherwise exempt from the operating requirements in Articles 1.8.3, 1.8.3.1, 1.8.3.2, and 1.8.3.4 of this Agreement.

1.8.3.4 Electric Storage Resources. Interconnection Customer interconnecting a Small Generating Facility that is an electric storage resource shall establish an operating range in Attachment 5 of its SGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Articles 1.8.3, 1.8.3.1, 1.8.3.2 and 1.8.3.3 of this Agreement. Attachment 5 shall specify whether the operating range is static or dynamic, and shall consider: (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by System Operator, Interconnecting Transmission Owner and Interconnection Customer. If the operating range is dynamic, then Attachment 5 must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Article 1.8.3.2 of this Agreement when it is online and dispatched to inject electricity to the New England Transmission System and/or receive electricity from the New England Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the New England Transmission System and/or dispatched to receive electricity from the New England Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement. Capitalized terms in Schedule 23 that are not defined in the Glossary of Terms shall have the meanings specified in Sections I.2.2. of the Tariff.

1.10 Scope of Service

1.10.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

NR for NR Interconnection Service (NR Capability Only)

CNR for CNR Interconnection Service (NR Capability and CNR Capability)

1.10.1.1 Capacity Network Resource Interconnection Service (CNR Interconnection Service)

(a) The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and the Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which all other CNRs are interconnected under the CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Small Generating Facility to be designated as a CNR to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the net CNR Capability, or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as all other existing Capacity Network Resources, and to be studied as a Capacity Network Resource on the assumption that such a designation will occur.

1.10.1.2 Network Resource Interconnection Service (NR Interconnection Service).

(a) The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in which all other Network Resources are interconnected under the NC Interconnection Standard.

NR Interconnection Service allows the Interconnection Customer's Small Generating Facility to participate in the New England Markets, in accordance with Market Rule, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule 1, Section III of the Tariff. Notwithstanding the above, the portion of a Small Generating Facility that has been designated as a Network Resource interconnected under the NC Interconnection Standard cannot be a capacity resource under Section III.13 of the Tariff, except pursuant to a new Interconnection Request for CNR Interconnection Service.

- 1.10.1.3 Provision of Service. System Operator and Interconnecting Transmission Owner shall provide Interconnection Service for the Small Generating Facility at the Point of Interconnection.
- 1.10.1.4 Performance Standards. Each Party shall perform all of its obligations under this SGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this SGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the SGIA and System Operator, in conjunction with the Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.
- 1.10.1.5 No Transmission Service Delivery. The execution of this SGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.
- 1.10.1.6 Transmission Delivery Service Implications. CNR Interconnection Service and NR Interconnection Service allow the Interconnection Customer's Small Generating Facility to be designated by any Network Customer under the Tariff on the New England Transmission System as a Capacity Network Resource or Network Resource, up to the net CNR Capability or NR Capability, respectively, on the same basis as all other existing Capacity Network Resources and Network Resources interconnected to the New England Transmission System, and to be studied as a Capacity Network Resource or a Network Resource on the assumption that such a designation will occur. Although CNR Interconnection Service and NR Interconnection

Service do not convey a reservation of transmission service, any Network Customer can utilize its network service under the Tariff to obtain delivery of capability from the Interconnection Customer's Small Generating Facility in the same manner as it accesses Capacity Network Resources and Network Resources. A Small Generating Facility receiving CNR Interconnection Service or NR Interconnection Service may also be used to provide Ancillary Services, in accordance with the Tariff and Market Rule 1, after technical studies and/or periodic analyses are performed with respect to the Small Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Capacity Network Resource or Network Resource. However, if an Interconnection Customer's Small Generating Facility has not been designated as a Capacity Network Resource or as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all Generating Facilities that are similarly situated.

CNR Network Interconnection Service and NR Interconnection Service do not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Small Generating Facility to any particular load on the New England Transmission System without incurring congestion costs. In the event of transmission constraints on the New England Transmission System, the Interconnection Customer's Small Generating Facility shall be subject to the applicable congestion management procedures for the New England Transmission System in the same manner as other Capacity Network Resources or Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that the Interconnection Customer's Small Generating Facility be designated as a Capacity Network Resource or as a Network Resource by a Network Customer under the Tariff or that the Interconnection Customer identify a specific buyer (or sink). To the extent a Network

Customer does designate the Small Generating Facility as either a Capacity Network Resource or a Network Resource, it must do so pursuant to the Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining CNR Interconnection Service or NR Interconnection Service, as long as the Small Generating Facility has not been deemed to be retired, any future transmission service request for delivery from the Small Generating Facility on the New England Transmission System of any amount of capacity capability and/or energy capability will not require that any additional studies be performed or that any further upgrades associated with such Small Generating Facility be undertaken, regardless of whether or not such Small Generating Facility is ever designated by a Network Customer as a Capacity Network Resource or Network Resource and regardless of changes in ownership of the Small Generating Facility. To the extent the Interconnection Customer enters into an arrangement for long-term transmission service for deliveries from the Small Generating Facility outside the New England Transmission System, or if the unit has been deemed to be retired, such request may require additional studies and upgrades in order for Interconnecting Transmission Owner to grant such request.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1. The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the System Operator and the Interconnecting Transmission Owner of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Interconnecting Transmission Owner may, at its own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe

the testing. The Interconnection Customer shall provide the Interconnecting Transmission Owner a written test report when such testing and inspection is completed.

2.1.2 The Interconnecting Transmission Owner shall provide the Interconnection Customer and the System Operator written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Interconnecting Transmission Owner of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Interconnecting Transmission Owner [and System Operator] shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Interconnecting Transmission Owner shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Interconnecting Transmission Owner shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the New England Transmission System [or Interconnecting Transmission Owner's transmission facilities] without prior written authorization of the Interconnecting Transmission Owner. The Transmission Provider will provide such authorization once the Transmission Provider receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Interconnecting Transmission Owner may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small

Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Interconnecting Transmission Owner at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Interconnecting Transmission Owner shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. System Operator and Interconnecting Transmission Owner shall promptly file this Agreement with the Commission upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and by mutual agreement of the Parties shall remain in effect for a period of ____ years, (Term to be specified in individual Agreements, but in no case should the term be less than ten years from the Effective Date or such other longer period as the Interconnection Customer may request) and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with the Commission of a notice of termination of this Agreement (if required), which notice has been accepted for filing by the Commission.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the System Operator and Interconnecting Transmission Owner 20 Business Days written notice.

3.3.2 Each Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the Interconnecting Transmission Owner's Interconnection Facilities. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this SGIA or such non-terminating Party otherwise is responsible for these costs under this SGIA.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

“Emergency Condition” shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission Owner, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New England Transmission System, the Interconnecting Transmission Owner’s Interconnection Facilities or any Affected System to which the New England Transmission System is directly connected; or (3) that, in the case of the Interconnection Customer, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. The System Operator and the Interconnecting Transmission Owner may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility in accordance with applicable provisions of the Operating Requirements. The System Operator and Interconnecting Transmission Owner shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the New England Transmission System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

3.4.2.1 **Outage Authority and Coordination.** The System Operator shall have the authority to coordinate facility outages in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party’s(ies’) facilities

as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

3.4.2.2 **Outage Schedules.** Outage scheduling, and any related compensation, shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

3.4.2.3 **Interruption of Service.** In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the System Operator or Interconnecting Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect System Operator's or Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.

3.4.3 Forced Outages

During any forced outage, the Interconnecting Transmission Owner [and the System Operator] may suspend interconnection service to effect immediate repairs on the New England Transmission System. The Interconnecting Transmission Owner shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Interconnecting Transmission Owner shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Interconnecting Transmission Owner shall notify the Interconnection Customer and the System Operator as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other

customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the New England Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Interconnecting Transmission Owner may disconnect the Small Generating Facility. The Interconnecting Transmission Owner shall provide the Interconnection Customer and the System Operator with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from: (1) the Interconnecting Transmission Owner before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the Interconnecting Transmission Owner's Interconnection Facilities; and (2) the System Operator before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the New England Transmission System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the System Operator's or the Interconnecting Transmission Owner's, as appropriate, prior written authorization, the latter shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the New England Transmission System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Interconnecting Transmission Owner shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Interconnecting Transmission Owner.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Interconnecting Transmission Owner's Interconnection Facilities.

4.2 Distribution Upgrades

The Interconnecting Transmission Owner shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Interconnecting Transmission Owner and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer shall be responsible for its share of all reasonable expenses, associated with operating, maintaining, repairing, and replacing such Distribution Upgrades, except to the extent that a retail tariff of, or an agreement with, the Interconnecting Transmission Owner or its distribution company affiliate, if appropriate, provides otherwise.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades, including Stand Alone Network Upgrades.

5.2 Network Upgrades

The Interconnecting Transmission Owner shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Interconnecting Transmission Owner and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Interconnecting Transmission Owner elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne by the Interconnection Customer.

5.2.1.1 Cost Allocation. Cost allocation of Generator Interconnection Related Upgrades shall be in accordance with Schedule 11 of Section II of the Tariff.

5.2.1.2 Compensation. Any compensation due to the Interconnection Customer for increases in transfer capability to the PTF resulting from its Generator Interconnection Related Upgrade shall be determined in accordance with Sections II and III of the Tariff.

5.3 Special Provisions for Affected Systems

The Interconnection Customer shall enter into separate related facilities agreements to address any upgrades to the Affected System(s) that are necessary for safe and reliable interconnection of the Interconnection Customer's Small Generating Facility.

5.4 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result

of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Interconnecting Transmission Owner shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties.

6.1.2 Within three months of completing the construction and installation of the Interconnecting Transmission Owner's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Transmission Provider shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Interconnecting Transmission Owner for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Interconnecting Transmission Owner shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Interconnecting Transmission Owner within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Interconnecting Transmission Owner shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by

agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party(ies) of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Interconnecting Transmission Owner's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Interconnecting Transmission Owner a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Interconnecting Transmission Owner in accordance with Section 7 of Schedule 11 of the Tariff. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Interconnecting Transmission Owner's Interconnection Facilities and Upgrades. In addition:

- 6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Interconnecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.
- 6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Interconnecting Transmission Owner and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

Notwithstanding any other provision of this Agreement, the liability, indemnification and insurance provisions of the Transmission Operating Agreement (“TOA”) or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnection Transmission Owner and the liability, indemnification and insurance provisions of the Tariff apply to the relationship between the System Operator and the Interconnection Customer and between the Interconnecting Transmission Owner and the Interconnection Customer.

7.1 Assignment

This Agreement may be assigned by a Party upon 15 Business Days prior written notice and opportunity to object by the other Parties; provided that:

- 7.1.1 The Parties may assign this Agreement without the consent of the other Parties to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the other Parties of any such assignment.
- 7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Interconnecting Transmission Owner or the System Operator, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Interconnecting Transmission Owner and the System Operator of any such assignment.
- 7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Party(ies) for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall a Party be liable to another Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

- 7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.
- 7.3.2 Each Party shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's(ies') action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.
- 7.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.
- 7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.
- 7.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall

notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, in no event shall a Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party(ies), either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party(ies) informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this

Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party(ies). Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party(ies) shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance Requirements

8.1 General Liability

The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment

being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Interconnecting Transmission Owner, except that the Interconnection Customer shall show proof of insurance to the Interconnecting Transmission Owner no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 Insurer Requirements and Endorsements

All required insurance shall be carried by reputable insurers qualified to underwrite insurance in the state where the interconnection is located having a Best Rating of “A-”. In addition, all insurance shall, (a) include Interconnecting Transmission Owner and System Operator as additional insureds; (b) contain a severability of interest clause or cross-liability clause; (c) provide that Interconnecting Transmission Owner and System Operator shall not incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days’ written notice to Interconnecting Transmission Owner and System Operator prior to cancellation, termination, or material change of such insurance; provided that to the extent the Interconnection Customer is satisfying the requirements of subpart (d) of this paragraph by means of a presently existing insurance policy, the Interconnection Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Interconnecting Transmission Owner and System Operator as required above.

If the requirement of clause (a) in the paragraph above prevents Interconnection Customer from obtaining the insurance required without added cost or due to written refusal by the insurance carrier, then upon Interconnection Customer’s written notice to Interconnecting Transmission Owner and System Operator, the requirements of clause (a) shall be waived.

8.3 Evidence of Insurance

Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnection Customer.

The Interconnection Customer is responsible for providing the Interconnecting Transmission Owner and the System Operator with evidence of insurance in compliance with this Tariff on an annual basis.

Prior to the Interconnecting Transmission Owner commencing work on Interconnection Facilities, Network Upgrades and Distribution Upgrades, the Interconnection Customer shall have its insurer furnish to the Interconnecting Transmission Owner and the System Operator certificates of insurance evidencing the insurance coverage required above. The Interconnection Customer shall notify and send to the Interconnecting Transmission Owner and the System Operator a certificate of insurance for any policy written on a "claims-made" basis. The Interconnecting Transmission Owner and the System Operator may at their discretion require the Interconnection Customer to maintain tail coverage for three years on all policies written on a "claims-made" basis.

8.4 Self Insurance

If Interconnection Customer is a company with a self-insurance program established in accordance with commercially acceptable risk management practices, Interconnection Customer may comply with the following in lieu of the above requirements as reasonably approved by the Interconnecting Transmission Owner and the System Operator:

- Interconnection Customer shall provide to Interconnecting Transmission Owner and System Operator, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure to a level of coverage equivalent to that required.
- If Interconnection Customer ceases to self-insure to the standards required hereunder, or if Interconnection Customer is unable to provide continuing evidence of Interconnection Customer's financial ability to self-insure, Interconnection Customer agrees to promptly obtain the coverage required under Article 8.1.

8.5 Interconnecting Transmission Owner Insurance

The Interconnecting Transmission Owner agrees to maintain general liability insurance or self-insurance consistent with the Interconnecting Transmission Owner's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Interconnecting Transmission Owner's liabilities undertaken pursuant to this Agreement.

Article 9. Confidentiality

9.1 Confidential Information shall include without limitation, all information governed by the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, and any confidential and/or proprietary information provided by a Party to the another Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party(ies) and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party(ies) as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or

proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

- 9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if the Commission, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this Agreement prior to the release of the Confidential Information to the Commission. The Party shall notify the other Party(ies) to this Agreement when it is notified by the Commission that a request to release Confidential Information has been received by the Commission, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

Article 10. Disputes

- 10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.
- 10.2 In the event of a dispute, a Party shall provide the other Party(ies) with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.
- 10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, any Party may contact the Commission's Dispute Resolution Service (DRS) for assistance in resolving the dispute.
- 10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical

expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.

- 10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for its pro-rata share of any costs paid to neutral third-parties.
- 10.6 If no Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then each Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

- 11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with Commission policy and Internal Revenue Service requirements.
- 11.2 Each Party shall cooperate with the other to maintain the other Party's(ies') tax status. Nothing in this Agreement is intended to adversely affect the Interconnecting Transmission Owner's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by the Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.1 Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Interconnecting Transmission Owner. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, this Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, there are no other agreements,

representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of the New England Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects the System Operator, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected to the New England Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric

reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party(ies), first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party(ies). The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party(ies) copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party(ies) for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

Consistent with Section 4.8 of Schedule 23, the Interconnecting Transmission Owner and the System Operator shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement under any applicable provision of the Federal Power Act and the Commission's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party(ies) and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national carrier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

[To be supplied]

If to the Interconnecting Transmission Owner:

[To be supplied]

If to the System Operator:

ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: 413-540-4203

With a copy to:

Billing Department

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: [To be supplied]

Interconnecting Transmission Owner[To be supplied]

System Operator: ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: 413-540-4203

With a copy to:

Billing Department

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by a Party to the other Party(ies) and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Phone: _____ Fax: _____

E-mail: _____

If to the Interconnecting Transmission Owner:

Phone: _____ Fax: _____

E-mail: _____

If to the System Operator:

Phone: _____ Fax: 413-540-4203

E-mail: geninterconn@iso-ne.com

With a copy to:

Billing Department

Facsimile: (413) 535-4024

E-mail: billingdept@iso-ne.com

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

[To be supplied]

Interconnecting Transmission Owner's Operating Representative:

[To be supplied]

System Operator's Operating Representative:

ISO New England Inc.

Attention: Generation Interconnection, Transmission Planning Department

One Sullivan Road

Holyoke, MA 01040-2841

Phone: _____ Fax: (413) 540-4203

E-mail: geninterconn@iso-ne.com

DUNS Numbers:

Interconnection Customer: [To be supplied]

Interconnecting Transmission Owner: [To be supplied]

13.5 Changes to the Notice Information

A Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

[Insert name of] (Interconnecting Transmission Owner)

Name: _____

Title: _____

Date: _____

[Insert name of] (Interconnection Customer)

Name: _____

Title: _____

Date: _____

ISO New England Inc. (System Operator)

Name: _____

Title: _____

Date: _____

ATTACHMENTS TO SGIA

- | | |
|--------------|---|
| Attachment 1 | Glossary of Terms |
| Attachment 2 | Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment |
| Attachment 3 | One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment and Upgrades |
| Attachment 4 | Milestones |
| Attachment 5 | Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs |
| Attachment 6 | Interconnecting Transmission Owner's Description of its Upgrades, and Best Estimates of Upgrade Costs |
| Attachment 7 | Commercial Operation Date |

Glossary of Terms

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Standards – The requirements and guidelines of NERC, NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Systems.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (1) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and survey, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard (“CC Interconnection Standard”) – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources and Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource (“CNR”) – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability (“CNR Capability”) – The MW quantity associated with CNR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Capacity Network Resource Group Study (“CNR Group Study”) – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service (“CNR Interconnection Service”) - The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer’s CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Cluster Enabling Transmission Upgrade (“CETU”) shall mean new significant transmission line infrastructure that consists of AC transmission lines and related terminal equipment having a nominal voltage rating at or above 115 kV or HVDC transmission lines and HVDC terminal equipment that is identified through the Clustering Enabling Transmission Upgrade Regional Planning Study conducted to accommodate the Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered. The CETU shall be considered part of a Generator Interconnection Related Upgrade and be categorized as Interconnection Facilities or Network Upgrades.

Cluster Enabling Transmission Upgrade Regional Planning Study (“CRPS”) shall mean a study conducted by the System Operator under Attachment K, Section II of the Tariff to identify the Cluster Enabling Transmission Upgrade and associated system upgrades to enable the interconnection of Interconnection Requests for which the conditions identified in Section 1.5.3.1 have been triggered.

Cluster Interconnection Facilities Study (“CFS”) shall mean an Interconnection Facilities Study performed using Clustering pursuant to Section 1.5.3.4.

Cluster Interconnection System Impact Study (“CSIS”) shall mean an Interconnection System Impact Study performed using Clustering pursuant to Section 1.5.3.3.

Cluster Participation Deposit shall mean the initial and additional deposit due under Sections 1.5.3.3.2.2 and 1.5.3.4.4.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – The date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Attachment 7 to the Standard Small Generator Interconnection Agreement.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner’s facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner’s Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Generating Facility – The Interconnection Customer’s device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer’s Interconnection Facilities.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking

board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Initial Synchronization Date – The date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date – The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner’s Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner – A Transmission Owner that owns, leases or otherwise possesses an interest in, or a Non-Incumbent Transmission Developer that is not a Participating Transmission Owner that is constructing, a portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Small Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner’s Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Attachment 2 to the Standard Small Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner’s Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer – Any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Small Generating Facility with the Administered Transmission System under the Standard Small Generator Interconnection Procedures.

Interconnection Customer’s Interconnection Facilities shall mean all facilities and equipment, as identified in Attachment 2 of the Standard Small Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification,

addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities – The Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study – A study conducted by the System Operator, Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 3.5 of the Standard Small Generator Interconnection Procedures.

Interconnection Facilities Study Agreement – The form of agreement contained in Attachment 8 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study – A preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 3.3 of the Standard Small Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the

Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection Feasibility Study Agreement – The form of agreement contained in Attachment 6 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request – The Interconnection Request (a) shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP; (iv) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (v) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System; or (vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service – The service provided by the System Operator and the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Small Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study – Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Small Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement – Any of the following agreements: the Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, and the Interconnection Facilities Study Agreement attached to the Standard Small Generator Interconnection Procedures.

Interconnection System Impact Study – An engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Small Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 3.3 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 3.3 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and 3.4.

Interconnection System Impact Study Agreement – The form of agreement contained in Attachment 7 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

Network Capability Interconnection Standard (“NC Interconnection Standard”)– The minimum criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Network Resource

Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Network Resource (“NR”) – The portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.

Network Resource Capability (“NR Capability”) – The MW quantity associated with NR Interconnection Service, calculated as described in Section II.48 of the Tariff.

Network Resource Interconnection Service (“NR Interconnection Service”) – The Interconnection Service selected by the Interconnection Customer to interconnect its Generating Facility to the Administered Transmission System in accordance with the Network Capability Interconnection Standard. An Interconnection Customer’s NR Interconnection Service shall be solely for the megawatt amount of the NR Capability. NR Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the New England Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Administered Transmission System to accommodate the interconnection of the Small Generating Facility with the Administered Transmission System. Network Upgrades do not include Distribution Upgrades.

Notice of Dispute – A written notice of a dispute or claim that arises out of or in connection with the Standard Small Generator Interconnection Agreement or its performance.

Operating Requirements – Any operating and technical requirements that may be applicable due to System Operator or the Interconnecting Transmission Owner’s requirements, including those set forth in the Small Generator Interconnection Agreement, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

Party– The System Operator, Interconnecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Administered Transmission System.

Queue Position -- The order of a valid request in the New England Control Area, relative to all other pending requests in the New England Control Area, that is established based upon the date and time of receipt of such request by the System Operator. Requests are comprised of interconnection requests for Generating Facilities, Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. References to a “higher-queued” Interconnection Request shall mean one that has been received by System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as “lower-queued.”

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – A Generating Facility having a maximum gross capability at or above zero degrees F of 20 MW or less.

Stand Alone Network Upgrades – Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Attachment 2 to the Standard Small Generator Interconnection Agreement.

Study Case shall have the meaning specified in Sections 3.3.2 and 3.4.3 of this SGIP.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, Interconnection Feasibility Study, Interconnection System Impact Study, and Interconnection Facilities Study.

Tariff – The System Operator’s or Affected System's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the Commission, and as amended or supplemented from time to time, or any successor tariff.

Trial Operation – The period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Upgrades – The required additions and modifications to the Administered Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

**Description and Costs of the Small Generating Facility,
Interconnection Facilities, and Metering Equipment**

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Interconnecting Transmission Owner. The Interconnecting Transmission Owner will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

I. DESCRIPTION OF MAJOR COMPONENTS

A. Small Generating Facility

(1) Description of Small Generating Facility.

[insert]

(2) The Small Generating Facility shall receive:

___ Network Resource Interconnection Service for the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer, and [insert gross and net at or above 0 degrees F] MW for Winter.

___ Capacity Network Resource Interconnection Service for: (a)(i) the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer and [insert gross and net at or above 0 degrees F] MW for Winter; and (ii) the CNR Capability at [insert net] MW for Summer and [insert net] MW for Winter, which shall not exceed [insert the maximum net MW electrical output of the Generating Facility at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter].

- (3) Detailed Description of Small Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	
Manufacturer	
Model	
Designation of Generator(s)	
Excitation System Manufacturer	
Excitation System Model	
Voltage Regulator Manufacturer	
Voltage Regulator Model	
Generator Ratings	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 90 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 50 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 20 Degrees F	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above zero Degrees F	
Station Service Load For Each Unit	
Overexcited Reactive Power at Rated MVA and Rated Power Factor	
Underexcited Reactive Power at Rated MVA and Rated Power Factor	

Generator Short Circuit and Stability Data	
Generator MVA rating	
Generator AC Resistance	
Subtransient Reactance (saturated)	
Subtransient Reactance (unsaturated)	
Transient Reactance (saturated)	
Negative sequence reactance	
Transformer Data	
Number of units	
Self Cooled Rating	
Maximum Rating	
Winding Connection (LV/LV/HV)	
Fixed Taps	
Z1 primary to secondary at self cooled rating	
Z1 primary to tertiary at self cooled rating	
Z1 secondary to tertiary at self cooled rating	
Positive Sequence X/R ratio primary to secondary	
Z0 primary to secondary at self cooled rating	
Z0 primary to tertiary at self cooled rating	
Z0 secondary to tertiary at self cooled rating	
Zero Sequence X/R ratio primary to tertiary	

B. Interconnection Facilities

[insert]

C. Metering Equipment

[insert]

D. Other Components

[insert]

II. INTERCONNECTION EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

A. Point of Change of Ownership; Point of Interconnection

[insert]

B. Description of Responsibilities

[insert]

III. PRICING ESTIMATES

A. Interconnection Facilities

[insert]

B. Metering Equipment

[insert]

C. Operation and Maintenance

[insert]

Attachment 3

**One-line Diagram Depicting the Small Generating Facility, Interconnection
Facilities, Metering Equipment, and Upgrades**

[insert]

Milestones

- 1. Milestones and Other Requirements:** The description and entries listed in the following table establish the required Milestones in accordance with the provisions of the SGIP and this SGIA. The referenced section of the SGIP or article of the SGIA should be reviewed to understand the requirements of each milestone.

Item No.	Milestone Description	Responsible Party	Date	SGIP/SGIA Reference
1	Submit updated data “as purchased”	Interconnection Customer	No later than 180 Calendar Days prior to Initial Synchronization Date	
2	Submit supplemental and/or updated data “as built/as-tested”	Interconnection Customer	Prior to Commercial Operation Date	
3	Provide quarterly written progress reports	Interconnection Customer and Interconnecting Transmission Owner	15 Calendar Days after the end of each quarter beginning the quarter that includes the date for Milestone #3 below and ending when the entire Small Generating	

			Facility and all required Interconnection Facilities and Network Upgrades are in place	
4	Deliver to Transmission Owner “as built” drawings, information and documents regarding Interconnection Customer’s Interconnection Facility	Interconnection Customer	If requested, within 120 Calendar Days after Commercial Operation date	

2. Milestones Applicable If Facilities Study Has Been Waived by Interconnection Customer:

Item No.	Milestone Description	Responsible Party	Date	SGIP/SGIA Reference
1	Siting approval for the Generating Facility and Interconnection Facilities	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(i)
2	Engineering of Interconnection Facilities approved by Interconnecting Transmission Owner	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(ii)

3	Commit to the ordering of long lead time material for Interconnection Facilities and system upgrades	Interconnection Customer	As agreed to by the Parties	SGIP § 3.4.5(iii)
4	In-Service Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	
5	Initial Synchronization Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	SGIP § 3.4.5(iv)
6	Commercial Operation Date	Interconnection Customer	Same as Interconnection Request unless subsequently modified	SGIP § 3.4.5(v)

3. Milestones Applicable Solely for CNR Interconnection Service. In addition to the Milestones above, the following Milestones apply to Interconnection Customers requesting CNR Interconnection Service:

Item #	Milestone	Responsible Party	Date	SGIP/SGIA Reference
1	Submit necessary requests for participation in the Forward Capacity Auction associated with the Generating Facility's requested Commercial Operation Date, in accordance with Section III.13 of the Tariff	Interconnection Customer		1.7.1.3(i)

2	Participate in a CNR Group Study	Interconnection Customer; System Operator		1.7.1.3(ii)
3	Qualify and receive a Capacity Supply Obligation in accordance with Section III.13 of the Tariff	Interconnection Customer		1.7.1.3(iii)
4	Complete a re-study of the applicable Interconnection Study to determine the cost responsibility for facilities and upgrades necessary to accommodate the Interconnection Request based on the results of the Forward Capacity Auction, Reconfiguration Auction or bilateral transaction through which the Interconnection Customer received a Capacity Supply Obligation	System Operator		1.7.1.3(iv)

**Additional Operating Requirements for the
New England Transmission System and Affected Systems Needed to Support
the Interconnection Customer's Needs**

The Interconnecting Transmission Owner shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the New England Transmission System.

I. OPERATING REQUIREMENTS

[Insert]

**Interconnecting Transmission Owner's
Description of its Upgrades
and Best Estimate of Upgrade Costs**

The Interconnecting Transmission Owner shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Interconnecting Transmission Owner shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

I. DESCRIPTION OF UPGRADES

A. Distribution Upgrades

[Insert]

B. Network Upgrades

[Insert]

(1) Stand Alone Network Upgrades

(2) Other Network Upgrades

C. Affected System Upgrades

[Insert]

D. Contingency Upgrades

(1) Long Lead Facility-Related Upgrades. The Interconnection Customer's Small Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility

achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

[insert list of upgrades]

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this SGIA in accordance with Article 7, and the System Operator will initiate all necessary steps to terminate this SGIA, in accordance with Article 3.

(2) Other Contingency Upgrades. *[e.g., list of upgrades associated with higher queued Interconnection Requests with SGIAs prior to this SGIA and any other contingency upgrades that the Parties may deem necessary for the interconnection of the Small Generating Facility.]*

E. Post-Forward Capacity Auction Re-study Upgrade Obligations.

[Insert any changes in upgrade obligations that result from re-study conducted post receiving a Capacity Supply Obligation in accordance with the Tariff.]

Commercial Operation Date

This Attachment 7 is a part of the SGIA between System Operator, Interconnecting Transmission Owner and Interconnection Customer.

[Date]

[Interconnecting Transmission Owner; Address]

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: _____ Small Generating Facility

Dear _____:

On [Date] [Interconnection Customer] has completed Trial Operation of Unit No. ____.
This letter confirms that [Interconnection Customer] commenced commercial operation of Unit No. ____ at the Small Generating Facility, effective as of [Date plus one day].

Thank you.

[Signature]

[Interconnection Customer Representative]

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

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

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area

meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

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

$$LRA_Z = Resources_Z + Proxy Units_Z - (Proxy Units Adjustment_Z(1-FOR_Z)) - (Firm Load Adjustment_Z(1-FOR_Z))$$

In which:

- LRA_Z = MW of Local Resource Adequacy Requirement for Capacity Zone Z;
- $Resources_Z$ = MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
- $Proxy Units_Z$ = MW of proxy unit additions in Load Zone Z;
- $Firm Load Adjustment_Z$ = MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
- FOR_Z = Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.
- $Proxy Units Adjustment$ = MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1

days/year.

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

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.
- (d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

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

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{RestofNewEngland} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

- (a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

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

(a) For the relevant Capacity Commitment Period, the network model shall include:

- (i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;
- (ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and
- (iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.

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

III.12.6.1. Process for Establishing the Network Model.

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

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

(c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the

transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

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

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

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

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

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

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

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

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

III.12.6.3. Evaluation Criteria.

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

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

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

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

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

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

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

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

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3 and 4A of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all

other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

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

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,
- (e) all Existing Distributed Energy Capacity Resources,

but shall exclude:

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

(g) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(h) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

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

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

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

For existing Active Demand Capacity Resources:

Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

For Distributed Energy Capacity Resources:

For each Distributed Energy Capacity Resource, the availability metric for each underlying technology type will be applied in the same manner as it would be applied if the Distributed Energy Capacity Resource were qualified as a generator or demand response resource.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

- (a) **Implement voltage reduction.** The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).
- (b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.
- (c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system

peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the

import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, “at criterion” system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC’s assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

- A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

- (i) The transmission system will be modeled using the following conditions:

1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
4. Qualified Existing Distributed Energy Capacity Resources reflecting their existing Qualified Capacity for the Capacity Commitment Period;
5. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

(ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.

(iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

B. In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

A. Adding Proxy Units within New England when the New England system is short of capacity. In modeling New England as part of the interconnected system, if New England is

short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.

- B. Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.
- C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

- D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity.** In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.
- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system

isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.

- C. Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections

shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.
- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).
- C.** The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- D.** The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- E.** For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity

Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

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

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4) or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, New Demand Capacity Resource, and New Distributed Energy Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit. The Lead Market Participant for a resource participating in a Forward Capacity Auction may not change in the 15 Business Days prior to, or during, that Forward Capacity Auction.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), a New Demand Capacity Resource or Existing Demand Capacity Resource (as defined in Section III.13.1.4), or a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (as defined in Section III.13.1.4A) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Generating Capacity Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A Market Participant that elects to have a resource that has previously been counted as a capacity resource participate in the Forward Capacity Auction as a New Generating Capacity Resource, must notify the ISO when the existing resource ceases to operate and the New Generating Capacity Resource commences operation. If a Market Participant with a resource that has previously been counted as a capacity resource elects, pursuant to Section III.13.3.4(a)(iii), to have the resource that has previously been counted as a capacity resource cover the Capacity Supply Obligation of a New Generating Capacity Resource and the resource that has previously been counted as a capacity resource must take an outage in

order for the New Generating Capacity Resource to commence Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff), then the Market Participant must notify the ISO that the outage is for the purpose of the New Generating Capacity Resource commencing Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than \$200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than \$100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The \$100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.

The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation.

(c) A Project Sponsor or Lead Market Participant making an election pursuant to this Section III.13.1.1.1.3 must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.3.A. Treatment of New Incremental Capacity and Existing Generating Capacity at the Same Generating Resource.

For incremental summer capacity seeking to participate in the Forward Capacity Auction pursuant to Section III.13.1.1.1.3 or incremental winter capacity that meets the investment thresholds in Section III.13.1.1.1.3 as applied to the resource's winter Qualified Capacity, if the incremental summer or winter capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental summer or winter capacity with excess existing winter or summer Qualified Capacity at that same resource, as appropriate, not to exceed the Qualified Capacity of the existing portion of the resource, in

order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than \$200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The \$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Retirement Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every Asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

- (a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;
- (b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the New England state in which it is geographically located. A resource physically located in United States federal waters directly adjacent to New England state maritime boundaries and directly interconnecting to the New England system is considered to be geographically located in the state where its Point of Interconnection is located;

- (c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Capacity Resource pursuant to Section III.13.1.1, and;

- (d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also have, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, a valid Interconnection Request under Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the FCM Deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes,

replaces, or satisfies any of the requirements of Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff); the project address or location, and if relevant, asset identification number; the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line

diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period pursuant to Section III.13.1.1.2.2.1.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits.** In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing.** In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders.** In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2(c) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction.** In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery.** In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing.** In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (c) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the

major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning.** In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation.** In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) and/or the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a Rationing Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is

expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. For incremental capacity qualified pursuant to Section III.13.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export 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 pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2 (re-powering), Section III.13.1.1.3 (incremental capacity), or Section III.13.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail

to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will (i) include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) and (ii) exclude any existing capacity that will be retired as of the start of the same Capacity Commitment Period. Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating

Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer, as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be

accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

- (a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;
- (b) whether the critical path schedule includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and
- (e) whether, in the case of an Intermittent Power Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and

verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

- (a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;
- (b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;
- (c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);
- (d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Resource; (ii) for the notification to a Conditional Qualified New Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Resource, the Queue Position of the Conditional Qualified New Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant may not elect Renewable Technology Resource treatment for the FCA associated with a Capacity Commitment Period beginning on or after June 1, 2025.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Capacity Resource shall submit a Renewable Technology Resource election form no later than two Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.1.1.6. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price

election for the same resource made pursuant to Section III.13.1.4.1.1.2.7 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

- (a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c), (d) and (e) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than five Business Days after the deadline for submitting Renewable Technology Resource elections.
- (b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.
- (c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.
- (d) The cap for each Capacity Commitment Period beginning on June 1, 2020 or June 1, 2021 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.
- (e) The cap for each Capacity Commitment Period beginning on June 1, 2022 or June 1, 2023 or June 1, 2024 is 514 MW minus the cumulative amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources in the first or second run of the primary auction-clearing process pursuant to Section III.13.2 for each Capacity Commitment Period that begins on or after June 1, 2021.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New

Import Capacity Resource (Section III.13.1.3), as a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4), or as a New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource (Section III.13.1.4A) shall be an Existing Generating Capacity Resource.

III.13.1.2.1.1. Attributes of Existing Generating Capacity Resources.

For purposes of Forward Capacity Auction qualification, a Market Participant may not change any Existing Generating Capacity Resource attribute (including but not limited to the resource's status as an Intermittent Power Resource) in the period beginning 20 Business Days prior to the Existing Capacity Retirement Deadline and ending with the conclusion of the Forward Capacity Auction. Outside of this period, any such change must be accompanied by documentation justifying the change.

III.13.1.2.1.2 Rationing Minimum Limit.

No later than 120 days before the Forward Capacity Auction Market Participants may specify a Rationing Minimum Limit for an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median

of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources.

The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Summer Intermittent Reliability Hours. If there are less than five full summer periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Winter Intermittent Reliability Hours. If there are less than five full winter periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource is associated with a New Generating Capacity Resource or New Distributed Energy Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings or Existing Distributed Energy Capacity Resource's positive summer Seasonal DECR Audit Values from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A] plus [the amount of the New Generating Capacity Resource or New Distributed Energy Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1, except that no data from the time period prior to the New Generating Capacity Resource or New Distributed Energy Capacity Resource's FCM Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource.

(b) Where an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource is associated with a New Generating Capacity Resource or New Distributed Energy Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource’s positive winter Seasonal Claimed Capability ratings or Existing Distributed Energy Capacity Resource’s positive winter Seasonal DECR Audit Values from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2 or Section III.13.1.4A.2.A.1.2] plus [the amount of the New Generating Capacity Resource or New Distributed Energy Capacity Resource’s capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource or New Distributed Energy Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource’s winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2 or Section III.13.1.4A.2.A.1.2, except that no data from the time period prior to the New Generating Capacity Resource or New Distributed Energy Capacity Resource’s FCM Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Where the most recent summer Seasonal Claimed Capability or most recent summer Seasonal DECR Audit Value, as of the fifth Business Day in October, of an Existing Generating Capacity Resource (other than a Settlement Only Resource or an Intermittent Power Resource) and Existing Distributed Energy Capacity Resource (other than one comprised of Settlement Only Resources or an Intermittent Power Resource) is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1 and Section III.13.1.4A.2.A.1.1, respectively, by:

- (1) for Capacity Commitment Periods beginning prior to June 1, 2023, more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW;
- (2) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:
 - (i) the greater of 10 percent of that summer Qualified Capacity or two MW, or;

(ii) 10 MW;

then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability or summer Seasonal DECR Audit Value as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, Section III.13.1.4A.1.1.2.3, or Section III.13.1.4A.1.1.2.4, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1 by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 or Section III.13.1.4A.2.A.1.1 for the Forward Capacity Auction. For an Existing Generating Capacity Resource or Existing Distributed Energy Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource (other than a Settlement Only Resource) meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of

incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource, Existing Distributed Energy Capacity Resource, or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Capacity Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

Where an Existing Distributed Energy Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.4A.2.A, then that resource must have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

(a) For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the

resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource as described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire

resource. 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 any type of de-list or export 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. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds).

Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of 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.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

For the fifteenth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2024), the Dynamic De-List Bid Threshold is \$4.30/kW-month. For each Forward Capacity Auction thereafter, the Dynamic De-List Bid Threshold shall be calculated as described below in this Section III.13.1.2.3.1.A, and shall be published to the ISO's website no later than 5 Business Days before the Existing Capacity Retirement Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) below, a preliminary value of the Dynamic De-List Bid Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Forward Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.13.2.5.2.1(d), the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the

price at which the total amount of capacity clearing in the immediately preceding Forward Capacity Auction intersects the estimated System-Wide Capacity Demand Curve for the upcoming Forward Capacity Auction. For this purpose, the estimated System-Wide Capacity Demand Curve shall be constructed, in the same manner as described in Section III.13.2.2.1, using the system-wide Marginal Reliability Impact values from the immediately preceding Forward Capacity Auction, the most recent estimate of the Installed Capacity Requirement (net of HQICCs) for the upcoming Forward Capacity Auction, and the Net CONE and Forward Capacity Auction Starting Price for the upcoming Forward Capacity Auction.

(b) The preliminary value of the Dynamic De-List Bid Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction. The preliminary value of the Dynamic De-List Bid Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$\text{Margin} = \$1/kW\text{-month} \times \left[\frac{(75\% \times \text{Net CONE}_{\text{upcoming FCA}}) - \text{DDBT}_{\text{preliminary}}}{(75\% \times \text{Net CONE}_{\text{upcoming FCA}})} \right]$$

(d) The final value of the Dynamic De-List Bid Threshold for the upcoming Forward Capacity Auction shall be equal to the preliminary value of the Dynamic De-List Bid Threshold calculated pursuant to Sections III.13.1.2.3.1.A(a) and III.13.1.2.3.1.A(b) plus the margin value calculated pursuant to Section III.13.1.2.3.1.A(c).

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction qualification process. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs). The curve may in no case

increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

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 Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. [Reserved.]

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area, other than an Intermittent Power Resource or a Renewable Technology Resource, seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction qualification process. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction qualification process. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.5.2.4.

III.13.1.2.3.1.5. Permanent De-List Bids and Retirement De-List Bids.

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets

beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids and Retirement De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

III.13.1.2.3.1.5.1. Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-accepted Permanent De-List Bids and Internal Market Monitor-accepted Retirement De-List Bids that are at or above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee during the month of August following the issuance of retirement determination notifications pursuant to Section III.13.1.2.4(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than the fifth Business Day in the month of September following the review of system needs with the Reliability Committee per (b) above, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

(i) For a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).

(ii) For a Permanent De-List Bid at or above the Forward Capacity Auction Starting Price for which a Lead Market Participant has not elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid

will continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

III.13.1.2.3.1.6. Static De-List Bids, Permanent De-List Bids and Retirement De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, Permanent De-List Bid and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

- (i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.
- (ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.
- (iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-determined or Internal Market Monitor-accepted price for the bid as described in Section III.13.1.2.3.2.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and Export Bids, Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid and each Export Bid at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section

III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid at or above the Dynamic De-List Bid Threshold if the sum of all such bids at or above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor 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).

Sufficient documentation and information about each bid component must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Static De-List Bids and Export Bids.

The Internal Market Monitor shall review Static De-List Bids and Export Bids and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Static De-List Bid or an Internal Market Monitor-accepted Export Bid. The Internal Market Monitor-accepted Static De-List Bid and Internal Market Monitor-accepted Export Bid shall be equal to the Static De-List Bid or Export Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Static De-List Bid or Internal Market-Monitor-accepted Export Bid that is consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs.

If an Internal Market Monitor-determined price is established for a Static De-List Bid or an Export Bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(c) shall include an explanation of the Internal Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.

The Internal Market Monitor shall review those Permanent De-List Bids and Retirement De-List Bids identified in Section III.13.1.2.3.2.1 and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Permanent De-List Bid or an Internal Market Monitor-accepted Retirement De-List Bid. The Internal Market Monitor-accepted Permanent De-List Bid and Internal Market Monitor-accepted Retirement De-List Bid shall be equal to the Permanent De-List Bid or Retirement De-List Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Permanent De-List Bid or Internal Market-Monitor-accepted Retirement De-List Bid that is 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 retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-accepted price and the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with

other evidence. A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula.

Net Going Forward Costs =

$$\frac{(GFC - IMR) \times InfIndex}{(CQ_{Summer, kW}) \times (12 \text{ months})}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period.

$CQ_{Summer, kW}$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has indicated in the submission of a Static De-List Bid that the

resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00.

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: “i” is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant’s submitted data to ensure that it is consistent with overall market conditions and reflects expected values.

The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource’s expected cash flows as follows:

The net present value of the Existing Capacity Resource’s expected cash flows is equal to (i) the net present value of the Existing Capacity Resource’s net annual expected cash flows over the resource’s remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource’s expected terminal value, using the resource’s discount rate, divided by (ii) the product of the resource’s Qualified Capacity (in kilowatts) and 12 months.

The Existing Capacity Resource’s net annual expected cash flow for the first Capacity Commitment Period of the resource’s remaining economic life is the resource’s expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource's net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life is the resource's expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant's expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant's forecasted expected capacity prices with the Internal Market Monitor's estimate thereof in each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the

Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative. However, effective April 9, 2020, beginning with the sixteenth Forward Capacity Auction, the economic life is the evaluation period in which a resource's net present value is maximized.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid, Permanent De-List Bid, or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2.A may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Capacity Resource submitting a Static De-List Bid or an Export Bid, Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of

expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Static De-List Bid Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all Static De-List Bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\text{Cost Of Capital}}{(1 - (1 + \text{CostOfCapital})^{-\text{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity; Right to

Increase Retirement De-List Bid or Permanent De-List Bid up to IMM-determined substitution auction test price.

(a) No later than five Business Days before the Existing Capacity Qualification Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid, Retirement De-List Bid and substitution auction test price concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2 and Section III.13.2.8.3.1A. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5. For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, within five Business Days of the issuance of the retirement determination notification, a Lead Market Participant that submitted a Retirement De-List Bid or a Permanent De-List Bid and a substitution auction demand bid for the resource associated with the de-list bid, may make the following adjustments:

(i) for a Retirement De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Retirement De-List Bid, the Internal Market Monitor would have calculated a Retirement De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Retirement De-List Bid price that the Internal Market Monitor would have calculated;

(ii) for a Permanent De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Permanent De-List Bid, the Internal Market Monitor would have calculated a Permanent De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Permanent De-List Bid price that the Internal Market Monitor would have calculated.

(b) No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than five Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate 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) may

elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external demand resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network

Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Retirement Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3.A(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3.A(c) or the median amount of

the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

- (a) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

- (b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

- (c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3A for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3A, no later than 10 Business Days prior to the Existing Capacity Retirement Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3A.

Contract Description	MW	Contract End Date
NYPA: NY – NE: CMEEC	13.2	8/31/2025
NYPA: NY – NE: MMWEC	53.3	8/31/2025
NYPA: NY – NE: Pascoag	2.3	8/31/2025
NYPA: NY– NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate – NE	Up to 225	10/31/2016
VJO: Highgate – NE (extension)	Up to 6	October 2020

(beginning 11/01/2016)

VJO: Phase I/II – NE

Up to 110

10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission’s Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service.

Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

(a) For each New Import Capacity Resource, the Project Sponsor submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the contract period including the entire Capacity Commitment Period, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

(b) To qualify for Capacity Commitment Periods prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which the import capacity is qualifying, the Project Sponsor must submit documentation of one or more one-year contracts for each prior Capacity Commitment Period, entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract(s); the Project Sponsor must also satisfy the relevant requirements of Sections III.13.1.3.5.1(a) , III.13.1.3.5.2, III.13.1.9, and III.13.3.1.1.

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource for the length of the multi-year contract.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and

operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Project Sponsor entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Cost Information.

The offer information described in Section III.13.1.1.2.2.3 and Section III.A.21.2 may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade) that submitted a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5 may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO pursuant to Section III.13.1.1.2.2.3, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Capacity Resources.

To participate in a Forward Capacity Auction as a Demand Capacity Resource, a resource must meet the requirements of this Section III.13.1.4. Each Demand Capacity Resource shall be a minimum of 100 kW.

An Active Demand Capacity Resource comprises one or more Demand Response Resources located in a single Dispatch Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource comprises one or more Assets located in a single Load Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource may consist of Load Management measures, Distributed Generation measures, or a combination thereof, or may consist solely of Energy Efficiency measures. A Demand Capacity Resource may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit import or export bids or Administrative Export De-List Bids.

III.13.1.4.1. Definition of New Demand Capacity Resource.

A New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, and On-Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. A Demand Capacity Resource that has previously been defined as an Existing Demand Capacity Resource shall be considered a New Demand Capacity Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.1. Qualification Process for New Demand Capacity Resources.

For Forward Capacity Auctions a New Demand Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4. The FCA Qualified Capacity for a New Demand Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

(a) For a resource to qualify as a New Demand Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated demand reduction values and supporting information in the New Demand Capacity Resource Show of Interest

Form as described in Section III.13.1.4.1.1.1. Second, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package as described in Section III.13.1.4.1.1.2.

(b) For a resource to qualify as a New Demand Capacity Resource that is an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Project Sponsor must in addition submit, as part of the New Demand Capacity Resource Qualification Package, a Measurement and Verification Plan providing the documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.1, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.1. New Demand Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit to the ISO a New Demand Capacity Resource Show of Interest Form as described in this Section III.13.1.4.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. A New Demand Capacity Resource Show of Interest Form for a resource composed of Energy Efficiency measures must represent a resource with a new and unique resource identification number. The ISO may waive the submission of any information not required for evaluation of a project.

A completed New Demand Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Capacity Resource will be located; the Dispatch Zone within which an Active Demand Capacity Resource will be located; estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); estimated total summer and winter demand reduction value of the Demand Capacity Resource (for an Active Demand Capacity Resource, this estimate must be consistent with the baseline calculation methodology in Section III.8.2); supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values; Demand Capacity Resource type (Active Demand Capacity Resource, On-Peak Demand Resource, or Seasonal Peak Demand Resource); brief Demand Capacity Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; the date by which the Project Sponsor expects to be

ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value; ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; for individual Distributed Generation projects and Demand Capacity Resource projects from a single facility with a demand reduction value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.1.1.2. New Demand Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Capacity Resource Qualification Package shall conform to the requirements of this Section

III.13.1.4.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Demand Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4.1.1.2.2. Measurement and Verification Plan.

For On-Peak Demand Resources and Seasonal Peak Demand Resources, the Project Sponsor must provide in the New Demand Capacity Resource Qualification Package a Measurement and Verification Plan that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.2.3. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Demand Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of

target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Demand Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's Net Supply Capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

III.13.1.4.1.1.2.4. Critical Path Schedule for a Demand Capacity Resource with a Demand Reduction Value of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Demand Capacity Resource with a demand reduction value of at least 5 MW at a single Retail Delivery Point shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.1.1.2.5. Critical Path Schedule for a Demand Capacity Resource with All Retail Delivery Points Having a Demand Reduction Value of Less Than 5 MW.

The Project Sponsor of a Demand Capacity Resource with all Retail Delivery Points having a demand reduction value of less than 5 MW shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value must be complete.

III.13.1.4.1.1.2.6. [Reserved.]

III.13.1.4.1.1.2.7. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.4.1.1.2.7 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Demand Capacity Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Capacity Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) 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. If no such election is made in the New Demand Capacity Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Capacity Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Capacity Resource offer clears. If the Project Sponsor elects 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, then the Project Sponsor may not change the Demand Capacity Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Capacity Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export 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 pursuant to this Section III.13.1.4.1.1.2.7.

III.13.1.4.1.1.2.8. Offer Information From New Demand Capacity Resources.

(a) All New Demand Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Capacity Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

(b) The Project Sponsor for a New Demand Capacity Resource must indicate in the New Demand Capacity Resource Qualification Package if an offer from the New Demand Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.1.1.3. Initial Analysis for Active Demand Capacity Resources.

For each New Demand Capacity Resource that is an Active Demand Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Demand Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.1.4. Consistency of the New Demand Capacity Resource Qualification Package and New Demand Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Capacity Resource Qualification Package for consistency with its New Demand Capacity Resource Show of Interest Form. The New Demand Capacity Resource Qualification Package may not contain material changes relative to the New Demand Capacity Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Capacity Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Active Demand Capacity Resource is located; (iv) a change in the total summer or winter demand reduction value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); or (vi) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.1.1.5. Evaluation of New Demand Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Demand Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by New Demand Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Capacity Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Capacity Resource are satisfied; and
- (e) whether, in the case of a New Demand Capacity Resource that is an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.6. Qualification Determination Notification for New Demand Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Capacity Resource indicating whether the New Demand Capacity Resource has been accepted for participation in the Forward Capacity Auction.

- (a) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Capacity Resource type and the Demand Capacity

Resource's summer and winter Qualified Capacity, which shall be the ISO-determined summer and winter demand reduction value increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Demand Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.2. Definition of Existing Demand Capacity Resources.

Demand Capacity Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Capacity Resources, shall be Existing Demand Capacity Resources.

Existing Demand Capacity Resources shall include and are limited to Demand Capacity Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in this Section III.13.1.4, Existing Demand Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Capacity Resources shall be subject to Section III.13.1.2.2.5.2. An On-Peak Demand Resource or Seasonal Peak Demand Resource may not include in its summer or winter demand reduction value an Energy Efficiency measure whose Measure Life will expire before the beginning of the applicable season of the associated Capacity Commitment Period.

III.13.1.4.2.A Qualified Capacity for Existing Demand Capacity Resources.

(a) For Existing Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the lesser of: (i) the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Existing Capacity Qualification Deadline (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer (or winter, as applicable) capacity that has cleared in a Forward Capacity Auction and has not yet achieved FCM Commercial Operation (provided that such capacity is being monitored by the ISO pursuant to the provisions of Section III.13.3, is expected to achieve all its critical path schedule milestones prior to the start of the applicable season of the relevant Capacity Commitment Period, and for

which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy) and (ii) the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Demand Capacity Resource.

(b) For Existing Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the summer and winter demand reduction value, respectively, increased by average avoided peak transmission and distribution losses.

III.13.1.4.2.1. Qualified Capacity Notification for Existing Demand Capacity Resources.

(a) For each Existing Demand Capacity Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Retirement Deadline of: the Demand Capacity Resource type; summer and winter Qualified Capacity; the Load Zone in which the Demand Capacity Resource is located; and, for Active Demand Capacity Resources, the Dispatch Zone in which the resource is located.

(b) If the Lead Market Participant believes that the ISO's assessment of the Qualified Capacity is inaccurate, the Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) If a Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource wishes to change its Demand Capacity Resource type, the Market Participant must submit an Updated Measurement and Verification Plan to reflect the change in its resource type. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Capacity Resource type may not be changed during the Capacity Commitment Period.

(d) A Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource may provide an Updated Measurement and Verification Plan as described in Section III.13.1.4.3.1.2 that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after receipt of the Qualified Capacity notification.

(e) If an Existing Demand Capacity Resource is not submitting a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification.

III.13.1.4.2.2. Existing Demand Capacity Resource De-List Bids.

An Existing Demand Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Assets associated with Existing Demand Capacity Resources as New Demand Capacity Resources.

III.13.1.4.3. Measurement and Verification Applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

To demonstrate the demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Project Sponsor or Market Participant of such a resource participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals, or reconfiguration auctions shall submit to the ISO the Measurement and Verification Documents in accordance with this Section III.13.1.4.3 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents.

Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Resource or Seasonal Peak Demand Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall serve as the basis for the claimed demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall document the measurement and verification

performed to verify the achieved demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall contain a projection of the On-Peak Demand Resource's or Seasonal Peak Demand Resource's demand reduction value for each month of the Capacity Commitment Period and over the expected Measure Lives associated with the Demand Capacity Resources. An On-Peak Demand Resource's or Seasonal Peak Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Resource or Seasonal Peak Demand Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Project Sponsor's total demand reduction value from eligible pre-existing measures and new measures, and the Project Sponsor's total demand reduction value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Project Sponsor, the Measurement and Verification Documents for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Project Sponsor, an Updated Measurement and Verification Plan for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Capacity Resource project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total claimed demand reduction value or the Demand Capacity Resource type from the applicable Forward Capacity Auction in which the Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Capacity Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Project Sponsors for On-Peak Demand Resources and Seasonal Peak Demand Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's

utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction value and measures installed by Load Zone and meter domain. Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor or Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4A. Distributed Energy Capacity Resources.

To participate in a Forward Capacity Auction as a Distributed Energy Capacity Resource, a resource must meet the requirements of this Section III.13.1.4A. Each Distributed Energy Capacity Resource shall be a minimum of 100 kW. A facility connected at a point of interconnection that is 5 MW or greater cannot be a Distributed Energy Capacity Resource. A Distributed Energy Capacity Resource comprises one or more Distributed Energy Resource Aggregations located in a single Capacity Zone and a single DRR Aggregation Zone, except that (a) a Settlement Only Distributed Energy Resource Aggregation may not participate in a Distributed Energy Capacity Resource with any other type of Distributed Energy Resource Aggregation, and (b) an end-use customer facility participating as part of On-Peak Demand Resource or Seasonal Peak Demand Resource with measures other than Energy Efficiency may not participate in a

Distributed Energy Capacity Resource. Distributed Energy Capacity Resources are not permitted to submit import or export bids or Administrative Export De-List Bids.

III.13.1.4A.1. Definition of New Distributed Energy Capacity Resources.

A New Distributed Energy Capacity Resource is a Distributed Energy Capacity Resource that has not cleared in a previous Forward Capacity Auction.

III.13.1.4A.1.1. Qualification Process for New Distributed Energy Capacity Resources.

For Forward Capacity Auctions a New Distributed Energy Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated net injection capability and, as applicable, the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4A. The FCA Qualified Capacity for a New Distributed Energy Capacity Resource (other than an Intermittent Power Resource) shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity.

For a resource to qualify as a New Distributed Energy Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated net energy injection values and, as applicable, estimated demand reduction values and supporting information in the New Distributed Energy Capacity Resource Show of Interest Form as described in Section III.13.1.4A.1.1.1. Second, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package as described in Section III.13.1.4A.1.1.2.

III.13.1.4A.1.1.1. New Distributed Energy Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit to the ISO a New Distributed Energy Capacity Resource Show of Interest Form as described in this Section III.13.1.4A.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project.

(a) General Requirements. A completed New Distributed Energy Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; the DRR Aggregation Zone, Load Zone and Dispatch Zone within which the resource will be located; a description of the project and its expected configuration, including the types of generation and demand response

comprising the project; a description of the customer classes and end-uses served by the project; the resource's expected Commercial Operation date; estimated summer and winter net injection capability values (MW) per facility; the installation date of facilities that are part of the project and already constructed, installed, or in commercial operation; ISO Market Participant status and ISO customer identification (if applicable); Project Sponsor's contact information and the ISO Customer Status; expected nameplate capacity by technology type per facility; indication of whether the project elects Intermittent Power Resource treatment (available if the project is a homogenous aggregation of intermittent technology); and the project's applicable technical and financial contacts.

For purposes of this Section III.13.1.4A:

(i) If a facility is expected to interconnect at a point of interconnection, its net injection capability is the generation capability of the installed generation technology at the point of interconnection.

(ii) If a facility is expected to interconnect at a Retail Delivery Point and does not plan to participate in the aggregation as a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, the net injection capability is the lesser of the generation less the load profile measured at the location of the end-use customer meter or the amount the facility is contractually able to inject.

(b) Demand Response Resource. If the resource includes Demand Response Resources, the completed New Distributed Energy Capacity Resource Show of Interest Form shall include the following additional information: the estimated summer and winter demand reductions values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); the estimated total summer and winter demand reduction value of the Demand Response Resource (which must be consistent with the baseline calculation methodology in Section III.8.2); and supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values.

(c) Net Injection of 5 MW or Greater. If the resource contains a Distributed Energy Resource Aggregation with a facility with net injection of 5 MW or greater at a Retail Delivery Point, then the completed New Distributed Energy Capacity Resource Show of Interest Form for such a resource shall include the following additional information: the Pnode and service address at which the end-use facility is located; nameplate MW and net injection capability; non-coincident peak load (MW) of the facility without generation; technology type; and the Market Participant's portion of generation requested to be included as Qualified Capacity.

(d) Net Injection Greater or Equal to 1 MW and less than 5 MW. If the resource contains a Distributed Energy Resource Aggregation with a facility that has net injection capability at the point of interconnection of 1 MW or greater and less than 5 MW, then the completed New Distributed Energy Capacity Resource Show of Interest Form for such a facility shall include the following additional information: distribution bus; technology type; nameplate MW; one-line diagram of the plant and station facilities, including any known transmission facilities; if the facility is intermittent, the requested contribution of Qualified Capacity and supporting site-specific data; if an interconnection agreement is required under state requirements, the date when the interconnection request was submitted and the status of that interconnection request.

III.13.1.4A.1.1.2. New Distributed Energy Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must submit a New Distributed Energy Capacity Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Distributed Energy Capacity Resource Qualification Package shall conform to the requirements of this Section III.13.1.4A.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4A.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Distributed Energy Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4A.1.1.2.2. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Distributed Energy Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Distributed Energy Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's net injection capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

(c) The requirements of this Section III.13.1.4A1.1.2.2 shall not apply for facilities with a net injection capability equal to or greater than 1 MW and less than 5 MW at a point of interconnection.

III.13.1.4A.1.1.2.3. Critical Path Schedule for a Distributed Energy Capacity Resource Having a Facility with a Demand Reduction Value or Net Injection Capability of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Distributed Energy Capacity Resource with a customer facility having a demand reduction value of at least 5 MW at a single Retail Delivery Point or having behind-the-meter generation with net injection capability greater than 5 MW at a single Retail Delivery Point, shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4A.1.1.2.4. Critical Path Schedule for a Distributed Energy Capacity Resource with All Facilities Having a Demand Reduction Value or Net Injection Capability of Less Than 5 MW at a Single Retail Delivery Point or Point of Interconnection.

The Project Sponsor of a Distributed Energy Capacity Resource with all facilities having a demand reduction value or net injection capability of less than 5 MW at a single Retail Delivery Point or point of interconnection shall provide in the New Distributed Energy Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value and net injection capability achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project Sponsor expects to

be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value and net injection capability must be complete.

III.13.1.4A.1.1.2.5. Additional Requirements for Distributed Energy Capacity Resources that are Intermittent Power Resources

In addition to the information described elsewhere in this Section III.13.1.4A.1.1.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III. 13.1.4A.1.1.2 (b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.4A.1.1.2.6. Offer Information From New Distributed Energy Capacity Resources.

The Project Sponsor for a New Distributed Energy Capacity Resource must indicate in the New Distributed Energy Capacity Resource Qualification Package if an offer from the New Distributed Energy Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4A.1.1.3. Initial Analysis for Distributed Energy Capacity Resources.

For each New Distributed Energy Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Distributed Energy Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity

Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Distributed Energy Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Distributed Energy Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4A.1.1.4. Consistency of the New Distributed Energy Capacity Resource Qualification Package and New Distributed Energy Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package for consistency with its New Distributed Energy Capacity Resource Show of Interest Form. The New Distributed Energy Capacity Resource Qualification Package may not contain material changes relative to the New Distributed Energy Capacity Resource Show of Interest Form. If a material change exists between the New Distributed Energy Capacity Resource Qualification Package and the New Distributed Energy Capacity Resource Show of Interest Form, the New Distributed Energy Capacity Resource Show of Interest Form will be withdrawn by the ISO. A material change includes, but is not limited to the following: (i) a misrepresentation or change of the interconnection status of a facility within the New Distributed Energy Capacity Resource; (ii) the addition of facilities at a point of interconnection with net injection capability greater than 1 MW; (iii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iv) a change in DRR Aggregation Zone within which the project is located; (v) for any component of the New Distributed Energy Capacity Resource that is a Demand Response Resource, an aggregate change in the total summer or winter demand reduction values of all such Demand Response Resources by more than 30 percent; (vi) for any component of the New Distributed Energy Capacity Resource with net injection capability less than 5 MW, a change in the total summer or winter net injection capability of the resource by more than 30 percent; (vii) for non-demand response components of a New Distributed Energy Capacity Resource, the introduction of a new technology type for the New Distributed Energy Capacity Resource; (viii) for demand response components of a the New Distributed Energy Capacity Resource, a change to the technology type providing demand reduction for the New Distributed Energy Capacity Resource; (ix) for a facility that interconnects at a point of interconnection, any increase in size of the facility; (ix) for

any non-demand response components of any New Distributed Energy Capacity Resource that interconnects at a point of interconnection, a decrease in size greater than 60 percent for any facility with greater than 1 MW connected at the same point of interconnection.

III.13.1.4A.1.1.5. Evaluation of New Distributed Energy Capacity Resource Qualification Materials.

The ISO shall review the information submitted by New Distributed Energy Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4A and whether, based on the information provided, the Distributed Energy Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by New Distributed Energy Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4A;
- (b) whether the critical path schedule submitted by New Distributed Energy Capacity Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Distributed Energy Capacity Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Distributed Energy Capacity Resource are satisfied; and
- (e) whether the customer acquisition plan and source of funding plan are sufficiently detailed and reasonably achievable.

III.13.1.4A.1.1.6. New Distributed Energy Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Distributed Energy Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.4A.2.A.1, as confirmed by

the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity.

III.13.1.4A.1.1.7. Qualification Determination Notification for New Distributed Energy Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Distributed Energy Capacity Resource indicating whether the New Distributed Energy Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Distributed Energy Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Distributed Energy Capacity Resource's summer and winter Qualified Capacity, which shall be, which shall be the ISO-determined summer and winter net injection capability and demand reduction value, which in the latter case shall be increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Distributed Energy Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4A.2. Definition of Existing Distributed Energy Capacity Resources.

Existing Distributed Energy Capacity Resources shall include Distributed Energy Capacity Resources that have cleared in a previous Forward Capacity Auction. Except as specified in this Section III.13.1.4A, Existing Distributed Energy Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Distributed Energy Capacity Resources shall be subject to Section III.13.1.2.2.5.2. Any Distributed Energy Resource Aggregation that is part of an Existing Capacity Resource shall count only as existing Qualified Capacity, and shall not count toward the Qualified Capacity of a New Distributed Energy Capacity Resource. Any Existing Generating Capacity Resource or Existing Demand Capacity Resource that could qualify as an Existing Distributed Energy Capacity Resource may convert to an Existing Distributed Energy Capacity Resource.

III.13.1.4A.2.A Qualified Capacity for Existing Distributed Energy Capacity Resources.

III.13.1.4A.2.A.1 Existing Distributed Energy Capacity Resources Other Than Intermittent Power Resources

III.13.1.4A.2.A.1.1 Summer Qualified Capacity

The summer Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's summer Seasonal Audit Value from the five most recent years, as of the fifth Business Day in October of each year, with only positive summer value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five summer Seasonal Audit Values, then the summer Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous summer Seasonal Audit Values, as of the fifth Business Day in October of each year, with only positive summer values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.1.2 Winter Qualified Capacity

The winter Qualified Capacity of an Existing Distributed Energy Capacity Resource that is not an Intermittent Power Resource shall equal the median of the resource's winter Seasonal Audit Value from the five most recent years, as of the fifth Business Day in June of each year, with only positive winter value included in the median calculation. Where an Existing Distributed Energy Capacity Resource has fewer than five winter Seasonal Audit Values, then the winter Qualified Capacity for that Existing Distributed Energy Capacity Resource shall be equal to the median of all of that resource's previous winter Seasonal Audit Values, as of the fifth Business Day in June of each year, with only positive winter values included in the median calculation. If for an Existing Distributed Energy Capacity Resource there are no previous Seasonal Audit Values because the resource had not yet achieved FCM Commercial Operation, then the Existing Distributed Energy Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Distributed Energy Capacity Resource in previous Forward Capacity Auctions.

III.13.1.4A.2.A.2 Existing Distributed Energy Capacity Resources That Are Intermittent Power Resources

Existing Distributed Energy Capacity Resources that are Intermittent Power Resources shall follow the same rules for Existing Generating Capacity Resources that are Intermittent Power Resources in section III.13.1.2.2.2. The Existing Qualified Capacity may not be greater than the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Distributed Energy Capacity Resource.

III.13.1.4A.2.A.3 Qualified Capacity Adjustment for Partially New and Partially Existing Resources

Rules related to a Distributed Energy Capacity Resource's Qualified Capacity Adjustment for Partially New and Partially Existing Resources can be found in Section III.13.1.2.2.3.

III.13.1.4A.2.A.4 Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Rules related to a Distributed Energy Capacity Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline can be found in Section III.13.1.2.2.4.

III.13.1.4A.2.1. Qualified Capacity Notification for Existing Distributed Energy Capacity Resources.

(a) For each Existing Distributed Energy Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the DRR Aggregation Zone in which the Existing Distributed Energy Capacity Resource is located.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Distributed Energy Capacity Resource, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Distributed Energy Capacity Resource does not submit a Static De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.4A.2.2. Existing Distributed Energy Capacity Resource De-List Bids.

An Existing Distributed Energy Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Distributed Energy Resource Aggregations associated with Existing Distributed Energy Capacity Resources as New Distributed Energy Capacity Resources.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.4.1.1.6. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Capacity Resource, April through November where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Capacity Resource, December through March where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (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 its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Capacity Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Offers composed of separate resources are subject to the locational restrictions specified in the following table:

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained Capacity Zone is located)

	Nested Export- Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)
--	--	------------	------------	------------	--

(e) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource of the resource’s final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource’s financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource, an Existing Generating Capacity Resource, a New Distributed Energy Capacity Resource, or an Existing Distributed Energy Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. A New Distributed Energy Capacity Resource or Existing Distributed Energy Capacity Resource may only designate its net injection capability as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity’s Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource, Existing Import Capacity Resource, New Distributed Energy Capacity Resource, or Existing Distributed Energy Capacity Resource and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capacity if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy

Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Capacity Resource; and (ii) 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 the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list, retire or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

- (a) Resource name, quantity and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (b) The quantity and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.
- (c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.
- (e) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids.
- (f) The name of each Lead Market Participant submitting Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b), and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to

full information about posted Static De-list Bids, Permanent De-List Bids, and Retirement De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

(g) No later than five Business Days after the close of the New Capacity Show of Interest Submission Window, the ISO shall post on its website the aggregate quantity of supply offers and demand bids that have been elected to participate in the substitution auction by Capacity Zone (where the zones used are those being studied for inclusion in the associated Forward Capacity Auction pursuant to Section III.12.4).

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Capacity Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Capacity Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Capacity Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Capacity Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, the financial assurance required prior to the auction

pursuant to FAP will be released pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Capacity Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Capacity Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4A, it shall lose its Capacity Supply Obligation and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Capacity Resource achieves FCM Commercial Operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource or the Elective Transmission Upgrade achieves FCM Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Capacity Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below (“Qualification Process Cost Reimbursement Deposit”). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project’s critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After

aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

<p>New Generating Capacity Resources \geq 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff</p>	<p>New Generating Capacity Resources $<$ 20 MW and \geq 2 MW</p>	<p>Imports and New Demand Capacity Resources</p>		<p>New Generating Capacity Resources $<$ 2 MW</p>
---	--	---	--	--

<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>	<i>Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources</i>			
\$25,000	\$7,500	\$1,000		\$500
<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>	<i>With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement</i>			
\$15,000	\$6,500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for FCM Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

- (a) each Capacity Commitment Period shall begin in June;

- (b) the Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment Period;
- (c) the New Capacity Show of Interest Submission Window will be in April, approximately four years and two months before the beginning of the Capacity Commitment Period;
- (d) the Existing Capacity Qualification Deadline will be 90 days after the Existing Capacity Retirement Deadline, approximately four years before the beginning of the Capacity Commitment Period;
- (e) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and
- (f) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity Auction prior to the ninth Forward Capacity Auction (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 its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource's multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

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, New Demand Capacity Resources, and New Distributed Energy 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, New Demand Capacity Resource, or New Distributed Energy 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, New Demand Capacity Resource, or New Distributed Energy 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, \dots, p_m , where $P_S > p_1 > p_2 > \dots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be q_1, q_2, \dots, 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:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \dots & \dots, \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

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, Existing Demand Capacity Resources and Existing Distributed Energy 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, Existing Demand Capacity Resource, and Existing Distributed Energy Capacity Resources 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, Existing Demand Capacity Resource, or Existing Distributed Energy 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.13.1.1.2.4 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.

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, New Demand Capacity Resources, and New Distributed Energy 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, Existing Demand Capacity Resources, and Existing Distributed Energy 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, Existing Demand Capacity Resource, or Existing Distributed Energy 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 reliability 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.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), a New Demand Capacity Resource (pursuant to Section III.13.1.4), or Distributed Energy Capacity Resource (pursuant to Section III.13.1.4A), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.3. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource's compliance with its critical path schedule after the Forward Capacity Auction unless the Project Sponsor previously requested pursuant to Section III.13.3.1.1 that the ISO continue to monitor that resource's compliance with its critical path schedule. However, if a New Generating Capacity Resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Resource, the ISO will not continue to monitor that resource's compliance with its critical path schedule even if that resource requested critical path schedule monitoring pursuant to Section III.13.3.1.1.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Project Sponsor does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Each critical path schedule report shall include the following:

III.13.3.2.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Project Sponsor should also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)) and Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW (discussed in Section III.13.3.2.2(c)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits.** For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing.** The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning.** The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades.** If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its

interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion.** The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements.** For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

(c) For Distributed Energy Capacity Resources with all Retail Delivery Points and facilities at the point of interconnection having in the aggregate a demand reduction value and net injection capability of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) Substantial Project Completion. The Project Sponsor shall provide documentation showing the total offered demand reduction value and net injection capability achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value and net injection capability achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Distributed Energy Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Distributed Energy Capacity Resource described in the Project Sponsor's New Distributed Energy Capacity Resource Qualification Package has achieved its full demand reduction value and net injection capability, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value and net injection capability must be complete.

(ii) Additional Requirements. For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Distributed Energy Resource Aggregation has been registered with the ISO, then the Project Sponsor shall also provide the Distributed Energy Resource Aggregation identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule or the feasibility that the project will achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, a New Demand Capacity Resource pursuant to Section III.13.1.4.1, or a New Distributed Energy Capacity Resource pursuant to Section III.13.1.4A and clearing in that auction, the Project Sponsor must provide information in the critical path

schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Project Sponsor to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Project Sponsor does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligations.

(a) If a capacity supplier determines that a resource may not be able to demonstrate its ability to deliver the full amount of its Capacity Supply Obligation, the capacity supplier may take actions to cover all or part of the Capacity Supply Obligation for any portion of the Capacity Commitment Period, as follows:

(i) A capacity supplier may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4.

(ii) A capacity supplier may cover its Capacity Supply Obligation through one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(iii) A capacity supplier that has qualified a resource pursuant to Section III.13.1.1.1.2 may cover its Capacity Supply Obligation by electing, no later than ten Business Days prior to the

offer and bid deadline for the third annual reconfiguration auction prior to the start of the applicable Capacity Commitment Period, to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource for up to two Capacity Commitment Periods. If an election is made to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource, the capacity supplier with the resource that was previously counted as a capacity resource shall be required to comply with the requirements set forth in Section III.13.6.1 so long as it continues to cover for the New Generating Capacity Resource.

(b) During a Capacity Commitment Period, a failure to cover charge will apply to any capacity resource that has not demonstrated the ability to deliver the full amount of its Capacity Supply Obligation by the end of an Obligation Month. The failure to cover charge is the difference between a resource's monthly Capacity Supply Obligation and its Maximum Demonstrated Output, multiplied by the Failure to Cover Charge Rate, where:

Maximum Demonstrated Output Period

Maximum Demonstrated Output Period is the period beginning six years prior to the start of the applicable Capacity Commitment Period and ending with the most recently completed calendar month in the Capacity Commitment Period, including all prior months in the Capacity Commitment Period.

Provided that, for a resource that has previously been counted as a capacity resource and for which an election has been made to participate as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2, and for which a cover election has been made pursuant to Section III.13.3.4(a)(iii), then: (1) the Maximum Demonstrated Output Period will be the Maximum Demonstrated Output Period of the resource that has been previously counted as capacity, and; (2) the Maximum Demonstrated Output Period of the New Generating Capacity Resource will begin on the earlier of: (i) the date that the resource that has previously been counted as a capacity resource began any outage as provided in Section III.13.1.1.1.2, and; (ii) the date that the New Generating Capacity Resource commenced Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

Failure to Cover Charge Rate

For Capacity Commitment Periods beginning prior to June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the higher of the Capacity Clearing Price and the clearing price in any annual reconfiguration auction for that Capacity Commitment Period.

For Capacity Commitment Periods beginning on or after June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the price determined by a second clearing of the third annual reconfiguration auction prior to the start of the Capacity Commitment Period in which the aggregated zonal quantities of undemonstrated Capacity Supply Obligation, as of the completion of the third annual reconfiguration auction, and as determined pursuant to Section III.13.3.4 (b), are included as demand bids at the Forward Capacity Auction Starting Price for each applicable Capacity Zone.

Provided that, if an existing resource is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the undemonstrated Capacity Supply Obligation for the New Generating Capacity Resource is the difference between the existing resource's Maximum Demonstrated Output and the new resource's Capacity Supply Obligation.

Maximum Demonstrated Output

The Maximum Demonstrated Output is the sum of the highest output levels achieved by each Generator Asset associated with a Generating Capacity Resource, each Demand Response Asset associated with an Active Demand Capacity Resources, assets associated with a Seasonal Peak Demand Resource or On-Peak Demand Resource, and each Distributed Energy Resource Aggregation associated with a Distributed Energy Capacity Resources during the Maximum Demonstrated Output Period as specified below. The minimum Maximum Demonstrated Output for all assets is zero.

Provided that, if a resource that was previously counted as capacity is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the Maximum Demonstrated Output is the sum of the highest aggregate output level achieved by each asset associated with the resource that has previously been counted as capacity during the Maximum Demonstrated Output Period.

At the asset level, Maximum Demonstrated Output is calculated as follows:

Demand Response Assets associated with an Active Demand Capacity Resource: The Maximum Demonstrated Output for dates occurring prior to June 1, 2018 is the highest audit value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses. The Maximum Demonstrated Output for dates occurring on or after to June 1, 2018 will be equal to the highest demand reduction calculated, pursuant to Section III.8.4, in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Distributed Generation associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly metered output in the Maximum Demonstrated Output Period after the resource has completed testing and has achieved commercial operation, increased by average avoided peak transmission and distribution losses for non-Net Supply.

Load Management associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly demand reduction value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Energy Efficiency associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest reported monthly performance value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses.

Generator Assets: The Maximum Demonstrated Output for dates occurring prior to March 1, 2017 is the highest hourly Revenue Quality Metering in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). The Maximum Demonstrated Output for dates occurring on or after March 1, 2017 is the highest Metered Quantity for Settlement in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

If a single Generator Asset is split into two or more new Generator Assets, the Maximum Demonstrated Output associated with the single Generation Asset will be prorated among the new assets based on their summer maximum net output. If multiple Generator Assets are consolidated to fewer assets, the Maximum Demonstrated Output of the Generator Assets that are being consolidated will be allocated to the consolidated assets based on the summer maximum net output.

Import Capacity Resources: For an Import Capacity Resource that is backed by external generation that has not achieved commercial operation at the time of qualification, in part or entirely, the Maximum Demonstrated Output is the highest revenue quality metered output for a five-minute or greater interval after the resource has completed testing and has achieved commercial operation. Provided that, the Maximum Demonstrated Output of an Import Capacity Resource associated with an Elective Transmission Upgrade may be limited by the highest demonstrated capability of the Elective Transmission Upgrade after the Elective Transmission Upgrade has completed testing and has achieved commercial operation.

Distributed Energy Resource Aggregations associated with a Distributed Energy Capacity Resource: The Maximum Demonstrated Output is the sum of the highest output levels achieved by each asset associated with the Distributed Energy Capacity Resource during the Maximum Demonstrated Output Period, pursuant to Section III.13.3.4.

III.13.3.4A Termination of Capacity Supply Obligations.

If a Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if a Project Sponsor covers a Capacity Supply Obligation for two Capacity Commitment Periods, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any

financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

If a resource's Capacity Supply Obligation that was acquired in a substitution auction at a negative price is withdrawn or terminated, the Project Sponsor shall remain obligated for any settlement charges associated with the terminated Capacity Supply Obligation for the Capacity Commitment Period.

III.13.3.5. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's Capacity Supply Obligation as described in Section III.13.3.4A, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4A.

III.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved FCM Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment

Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the resource's ability to achieve FCM Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Sections III.13.3.4(b), III.13.6 and III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves FCM Commercial Operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and 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) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7). A Project Sponsor will not take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4(a), but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an

additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.3.8. FCM Commercial Operation.

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, subject to the requirements of Section III.13.6.1.5.3(b).

(c) For an Import Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon demonstration that the Import Capacity Resource described in the New Capacity Qualification Package has achieved its full Qualified Capacity.

(d) For a Distributed Energy Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Distributed Energy Capacity Resource described in the New Distributed Energy Capacity Resource Qualification Package has achieved its full demand deviation value and net injection capability, subject to the requirements of Section III.13.6.1.7.3 and below.

(i) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value and net injection capability greater than 5 MW at a single Retail Delivery Point, these facilities shall map exactly to how the Distributed Energy Capacity Resource was qualified.

(ii) For facilities connected at a point of interconnection with net injection capability greater than or equal to 1 MW and less than 5 MW or facilities having a demand reduction value, to become fully commercial, the nameplate of each technology within the Distributed Energy Resource Aggregations mapped to the Distributed Energy Capacity Resource must be at least 70% of the expected nameplate of each technology used to support the Distributed Energy Capacity Resource Qualified Capacity.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of *Appendix A* of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated

Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction, or a demand bid that cleared in a substitution auction, for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period

and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources Backed By an External Control Area.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.3.1. Import Capacity Resources Backed by One or More External Resources.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the greater of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements

in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4. Demand Capacity Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or

permanently de-list prior to the start of the relevant Capacity Commitment Period) that is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any winter capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) that is

expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.1.5.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.5.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Import Capacity Resources.

III.13.4.2.1.2.2.3.1 Import Capacity Resources Backed by an External Control Area.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October.

III.13.4.2.1.2.2.3.2. Import Capacity Resources Backed by One or More External Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the lesser of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined by the most recent Forward Capacity Auction that does not reflect a change to the Import Capacity Resource applicable to that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4. Demand Capacity Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined summer Qualified Capacity and (2) its summer Seasonal DR Audit value or summer Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined winter Qualified Capacity and (2) its winter Seasonal DR Audit value or winter Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period and increased by average avoided peak transmission and distribution losses) and any winter capacity that has cleared in a Forward Capacity Auction and not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.5. Distributed Energy Capacity Resources.

III.13.4.2.1.2.2.5.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined summer Qualified Capacity and (ii) its summer Seasonal DECR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.5.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Distributed Energy Capacity Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below:

(a) For capacity that has achieved FCM Commercial Operation, the lesser of: (i) its most recently-determined winter Qualified Capacity and (ii) its winter Seasonal DECRA Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved FCM Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values (for Capacity Commitment Periods beginning on or before June 1, 2019) or the least of these 12 values (for Capacity Commitment Periods beginning on or after June 1, 2020), if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by:

- (1) for Capacity Commitment Periods beginning on or before June 1, 2019, more than the lesser of:
 - (i) 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or;
 - (ii) 40 MW;
- (2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, more than the lesser of:
 - (i) the greater of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;

- (ii) 40 MW;
- (3) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:
 - (i) the greater of 10 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;
 - (ii) 10 MW;

then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to:

- (1) for Capacity Commitment Periods beginning prior to June 1, 2020, the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3;
- (2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:
 - (i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.8), and;
 - (ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 40 MW;
- (3) for Capacity Commitment Periods beginning on or after June 1, 2023, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:

- (i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.9), and;
- (ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 10 MW.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource may not submit a supply offer for a monthly reconfiguration auction unless it is expected to achieve FCM Commercial Operation prior to the end of the relevant Obligation Month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. A resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between the values determined pursuant to subsections (a) and (b) below:

- (a) The resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period or, where the resource did not qualify for the third annual reconfiguration auction for the relevant Capacity Commitment Period, the quantity of MW either being monitored by the ISO in accordance with Section III.13.3 (provided that all applicable Financial Assurance requirements have been met and the resource is expected to achieve all its critical path schedule milestones prior to the end of the relevant Obligation Month in accordance with posted schedules) or the amount of capacity that achieved all its critical path schedule milestones after the third annual reconfiguration qualification deadline; provided that the value determined pursuant to this subsection (a) shall be limited by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f) or, for a Demand Capacity Resource, the amount of Qualified Capacity for the relevant Capacity Commitment Period.
- (b) The amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

- (a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.
- (b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.
- (c) All demand bids in reconfiguration auctions 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 reviews will consider the location and operating and rating limitations of resources associated with demand bids that would otherwise clear to ensure reliability standards will remain

satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation outage information, and will include transmission security studies. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. [Reserved.]

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, 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.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction

Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

The first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period.

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction for Capacity Commitment Periods beginning before June 1, 2020, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. For each monthly reconfiguration auction for Capacity Commitment Periods beginning or after June 1, 2020, the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.13.2.2.2 and Section III.13.2.2.3, and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

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, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation 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 settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. 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 monthly basis during the applicable Capacity Commitment Period. The monthly payment amount 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.13.6.1.7. Distributed Energy Capacity Resources with Capacity Supply Obligations.

III.13.6.1.7.1. Energy Market Offer Requirements.

(a) A Market Participant with a Distributed Energy Capacity Resource having a Capacity Supply Obligation shall submit offers for its Distributed Energy Resource Aggregations into the Day- Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.13.6.1.7.1; for purposes of the following comparisons, the portion of any Demand Reductions Offers or Baseline Deviation Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the offers must be equal to or greater than the Distributed Energy Capacity Resource's Capacity Supply Obligation whenever the Distributed Energy Resource Aggregations are physically available. If the Distributed Energy Resource Aggregations are physically available at a level less than the Distributed Energy Capacity Resource's Capacity Supply Obligation, the sum of the offers will equal that level and shall be offered into both the Day-Ahead Energy Market and

Real-Time Energy Market. Each offer from a Distributed Energy Resource Aggregation made into the Day- Ahead Energy Market shall also meet the following requirement:

- (i) the sum of the resource's notification time plus start-up time plus Minimum Run Time (or Minimum Deviation Time or Minimum Reduction Time) plus Minimum Down Time (or Minimum Time Between Deviations or Minimum Time Between Reductions) is less than or equal to 72 hours; or
- (b) Notwithstanding the foregoing, if the Distributed Energy Capacity Resource comprises Settlement Only Distributed Energy Resource Aggregations, it is not obligated to submit Supply Offers into the Day-Ahead Energy Market and may not submit Supply Offers into the Real-Time Energy Market.

III.13.6.1.7.2. Requirement that Offers Reflect Accurate Distributed Energy 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.

III.13.6.1.7.3. Additional Requirements for Distributed Energy Capacity Resources.

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

(a) A Market Participant may not associate an Asset with a non-commercial Distributed Energy Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Distributed Energy Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) Distributed Energy Capacity Resources shall comply with 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.

(c) Distributed Energy Capacity Resources shall comply with the auditing and rating requirements as detailed in this Market Rule 1 and the ISO New England Manuals.

(d) For Distributed Energy Capacity Resources, the Seasonal DECR Audit Value shall be established pursuant to Section III.1.7.13.

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. Distributed Energy Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.2.1. Energy Market Offer Requirements.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation is not required to submit offers for the resource into the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant with a Settlement Only Distributed Energy Resource Aggregation is not permitted to submit an offer for that resource into the Real-Time Energy Market.

III.13.6.2.2.2. Day-Ahead Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with a Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offer clears in the Day-Ahead Energy Market, the entire

offer, up to the maximum capability 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 so long as it is not a Settlement Only Distributed Energy Resource Aggregation.

III.13.6.2.2.3. Real-Time Energy Market Participation.

A Market Participant with a Distributed Energy Resource Aggregation that is not associated with a Distributed Energy Capacity Resource with 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 an offer in the Real-Time Energy Market so long as the resource is not a Settlement Only Distributed Energy Resource Aggregation, 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.13.6.2.2.4. Additional Requirements for Distributed Energy Capacity Resources Having No Capacity Supply Obligation.

Distributed Energy Capacity Resources without a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.1.7.3.

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, a Generating Capacity Resource, or a Distributed Energy 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:

(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:

$$\text{Hourly PER}(\$/\text{kW}) = [(\text{LMP} - \text{Adjusted Hourly PER Strike Price}) * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

Where:

$$\text{Adjusted Hourly PER Strike Price} = \text{Strike Price} + \text{Hourly PER Adjustment}$$

$$\text{Hourly PER Adjustment} = \text{average of Five-Minute PER Strike Price Adjustment values}$$

$$\text{Five-Minute PER Strike Price Adjustment} = \text{MAX} (\text{Thirty-Minute Operating Reserve clearing price} - \$500/\text{MWh}, 0) + \text{MAX} (\text{Ten-Minute Non-Spinning Reserve clearing price} - \text{Thirty-Minute Operating Reserve clearing price} - \$850/\text{MWh}, 0).$$

Strike Price = as defined below

Scaling Factor = as defined below

Availability Factor = as defined below

For all other hours:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{LMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

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_{location of the interface} - Capacity Clearing Price_{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_{location of the interface} - Capacity Clearing Price_{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 MWs of reduction, other than MWs 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.

(e) A Distributed Energy Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Metered Quantity for Settlement and Reserve Quantity for Settlement of all the components of its constituent Distributed Energy Resource Aggregations; 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. Based on the Real-Time operational coordination, the resource must follow any distribution system limitation and update its physical parameters accordingly. The Actual Capacity Provided cannot be less than zero.

(i) The Real-Time demand reduction of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation 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 or Demand Response Distributed Energy Resource Aggregation does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation 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 or Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation; 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:

$$\text{MaxCSO} \times [3 \text{ months} \times (\text{FCAcp} - \text{FCAsp}) - (12 \text{ months} \times \text{FCAcp})]$$

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 of the Obligation Month shall be subject to the following charges and adjustments:

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 III.13.7.5.1.1.1(b), III.13.7.5.1.1.2(b), III.13.7.5.1.1.3(b), III.13.7.5.1.1.6(b), III.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 III.13.7.5.1.1.1(b), III.13.7.5.1.1.2(b), III.13.7.5.1.1.3(b), III.13.7.5.1.1.6(b), III.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 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 Capacity Load Obligation in the Capacity Zone 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 Capacity 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.

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; when all load of a Distributed Energy Resource Aggregation participating as a Storage DARD is load associated with the receipt of electricity from the grid 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 month and 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 to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and 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, Demand Response Resource, or a Demand Response Distributed Energy Resource Aggregation.

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.

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, 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	Winter
									(MW)	(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.

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.

Marked Tariff

Effective November 1, 2026

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, 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.

Baseline Deviation Offer is an offer by a Market Participant with a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or inject additional energy.

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 each~~ hour); and (8) with respect to Baseline Deviation Offers administered by the ISO, a quantity of reduced demand or additional energy injection with a related price (Baseline Deviation Offers may contain multiple sets of quantity and price pairs for each hour).

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

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

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

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, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

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 or a Distributed Energy Resource associated

with a Demand Response Distributed Energy Resource Aggregation, 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.

Curtailement 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 Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

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 Distributed Energy Resource Aggregation Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy.

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 Distributed Energy Resource Aggregation Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Distributed Energy Resource Aggregation can reduce demand and/or inject additional energy.

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.

Demand Response Distributed Energy Resource Aggregation Start-Up Time is the period of time between the time a Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy at the conclusion of the Demand Response Distributed Energy Resource Aggregation Notification Time and the time the resource can reach its Minimum Deviation 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, or Demand Response Distributed Energy Resource Aggregation dispatched by the ISO in accordance with the asset's Offer Data.

Deviation Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Distributed Energy Resource Aggregation is scheduled or dispatched in the New England Markets to reduce demand and/or provide additional energy injection.

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 or Demand Response Distributed Energy Resource Aggregations, 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 or Baseline Deviation 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, Demand Response Distributed Energy Resource Aggregation, 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 or Baseline Deviation 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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal,

regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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, [Baseline Deviation 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, [Baseline Deviation 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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 Demand Response Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; (ii) Minimum Time Between Deviations does not exceed one hour; (iii) Demand Response Distributed Energy Resource Aggregation Start-Up Time plus Demand Response Distributed Energy Resource Aggregation 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.

Initial State of Charge is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

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 or an aggregation of wind, solar, run of river hydro and other renewable resources 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, Demand Reduction Offers or Baseline Deviation 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 Deviation is the maximum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer

Maximum Deviation Capability is an estimate of the maximum demand reduction and/or energy injection that a Distributed Energy Resource comprising a Demand Response Distributed Energy Resource Aggregation can deliver, as measured at the Retail Delivery Point and/or Point-of-Interconnection

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 or that a Demand Response Distributed Energy Resource Aggregation 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.

Maximum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

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 (MG TSA) 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), MG TSA 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 Deviation is the minimum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or

provide additional energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer.

Minimum Deviation Time is the minimum number of hours of baseline deviation at or above the Minimum Deviation for which the ISO must dispatch a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or provide additional energy injection.

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 State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

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 Time Between Deviations is the number of hours that must elapse after a Demand Response Distributed Energy Resource Aggregation has received a Dispatch Instruction to stop reducing demand and/or injecting additional energy before the Demand Response Distributed Energy Resource Aggregation can achieve its Minimum Deviation after receiving a Dispatch Instruction to start reducing demand and/or injecting additional energy.

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, New Demand Capacity Resource, or New Distributed Energy 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 Distributed Energy Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.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 Distributed Energy Capacity Resource Show of Interest Form is described in Section III.13.1.4A.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, and Demand

Response Distributed Energy Resource Aggregation operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, ~~and~~ Demand Response Resources and Demand Response Distributed Energy Resource Aggregations 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 or a Baseline Deviation 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 or a Fast Start Demand Response Distributed Energy Resource Aggregation that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed Energy Resource Aggregation 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, Settlement Only Distributed Energy Resource Aggregation, the energy injection and/or energy withdrawal portion of a Demand Response Distributed Energy

Resource Aggregation, 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. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Distributed Energy Resource Aggregation for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; and (ii) Demand Response Distributed Energy Resource Aggregation Notification Time plus Demand Response Distributed Energy Resource Aggregation 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 an 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 or, revised Baseline Deviation Offers associated with Demand Response Distributed Energy Resource Aggregation.

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, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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.

Round-Trip Efficiency is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

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 and Demand Response Distributed Energy Resource Aggregations 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 Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

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 of Charge is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

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 (TOUR 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 (TOUR 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.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 **[Reserved.]**

III.1.3.2 **[Reserved.]**

III.1.3.3 **[Reserved.]**

III.1.4 **Requirements for Certain Transactions.**

III.1.4.1 **ISO Settlement of Certain Transactions.**

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 **Transactions Subject to Requirements of Section III.1.4.**

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

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

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

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

- (iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and
- (iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

- (i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;
- (ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and
- (iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

- (i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and
- (ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

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

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) A Seasonal DRDERA Audit value determines the ability of a Demand Response Distributed Energy Resource Aggregation to perform during specified months for a specified duration.

~~(iii)~~(v) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's Establish Claimed Capability Audit value, ~~or~~ the Demand Response Resource's Seasonal DR Audit value or the Demand Response Distributed Energy Resource Aggregation's Seasonal DRDERA Audit value.

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

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) An Establish Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
 1. Non-intermittent daily cycle hydro;
 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and

3. Intermittent Generator Assets or Intermittent Settlement Only Distributed Energy Resource Aggregations
 - (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (d) For Generator Assets with an Establish Claimed Capability Audit value:
 - (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
 - (ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.
 - (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset or the sum of the maximum energy injection capabilities of the Settlement Only Distributed Energy Resource Aggregation's constituent Distributed Energy Resources.
- (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
- (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
 - (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit or the Settlement Only Distributed Energy Resource Aggregation's net output to increase from the current operating level to its maximum energy injection capability.

- (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	
Hydro-Conventional Weekly	
Wind	2
Photovoltaic	
Fuel Cell	
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
<u>Distributed Energy Resource Aggregation</u>	<u>2</u>
<u>Containing More Than One Technology Type</u>	

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2_(h) or a Settlement Only Distributed Energy Resource Aggregation consisting of a single technology type not listed in Section III.1.5.1.2 (h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets and Settlement Only Distributed Energy Resource Aggregation except:
 - (i) Non-intermittent daily hydro; and
 - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's or Settlement Only Distributed Energy Resource Aggregation's Seasonal Claimed Capability Audit obligation.
- (d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (e) A winter Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset or Settlement Only Distributed Energy Resource Aggregation for the audit time period and submitting to the ISO operational data that meets the following requirements:

- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
- (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
<u>Distributed Energy Resource Aggregation</u> <u>Containing More Than One Technology Type</u>	<u>2</u>

- (k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
 - (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (l) A Generator Asset or Settlement Only Distributed Energy Resource Aggregation that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
- (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset or Settlement Only Distributed Energy Resource Aggregation to perform

a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset or Settlement Only Distributed Energy Resource Aggregation during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

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

III.1.5.1.3.1 Seasonal DR Audits.

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.
- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;

- (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.
- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

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

III.1.5.1.3.2 Seasonal DRDERA Audits.

- (a) A Seasonal DRDERA Audit may be performed only for a Demand Response Distributed Energy Resource Aggregation.
- (b) A Seasonal DRDERA Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DRDERA Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or

- (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DRDERA Audit:
 - (i) The ISO shall perform the Seasonal DRDERA Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DRDERA Audit by issuing a Dispatch Instruction ordering the Demand Response Distributed Energy Resource Aggregation to its Maximum Deviation.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Baseline Deviation Offer parameters, to its Maximum Deviation.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DRDERA Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.2 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DRDERA Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DRDERA Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Distributed Energy Resource Aggregation Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DRDERA Audit as provided in this Section III.1.5.1.3.2 may be used to fulfill the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.
- (h) An ISO-Initiated Claimed Capability Audit fulfills the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.
 - (i) Each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation is evaluated during the Seasonal DRDERA Audit of the Demand Response Distributed Energy Resource Aggregation.

- (j) Any Distributed Energy Resource on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DRDERA Audit value (summer or winter) of a Demand Response Distributed Energy Resource Aggregation resulting from the Seasonal DRDERA Audit shall be the sum of the load reductions demonstrated during the audit by each of the Demand Response Distributed Energy Resource Aggregation's constituent Distributed Energy Resources plus the energy injected by the Demand Response Distributed Energy Resource Aggregation during the audit period.
- (l) If a Distributed Energy Resource is added to or removed from a Demand Response Distributed Energy Resource Aggregation between audits, the Demand Response Distributed Energy Resource Aggregation's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Distributed Energy Resource, such that at any point in time the summer or winter Seasonal DRDERA Audit value of a Demand Response Distributed Energy Resource Aggregation shall equal the sum of the most recent valid like-season audit values of its constituent Distributed Energy Resources.
- (m) The Seasonal DRDERA Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

The summer or winter audit value of a Distributed Energy Resource shall be set to zero at the end of the Capability Demonstration Year if the Distributed Energy Resource did not perform a Seasonal DRDERA Audit for that season as part of a Demand Response Distributed Energy Resource Aggregation during that Capability Demonstration Year.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource, shall replace either the summer or winter Seasonal DRDERA Audit value for a Demand Response Distributed Energy Resource Aggregation, and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation, normalized for temperature and steam exports, except:
 - (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability or equivalent interconnection agreements for that resource.

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

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource <u>or</u> <u>Demand Response Distributed Energy Resource</u> <u>Aggregations</u>	1
<u>Distributed Energy Resource Aggregation Containing</u> <u>More Than One Technology Type</u>	<u>2</u>

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

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer, Baseline Deviation Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to provide real-time energy or reserves.

- (b) Generator Asset audits shall be performed using the following methods for the relevant parameter:
- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
 - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response

Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) CLAIM30. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) Demand Response Distributed Energy Resource Aggregation audits shall be performed using the following methods:

(i) **Maximum Deviation.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve the current offered Maximum Deviation value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Distributed Energy Resource Aggregation Ramp Rate.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Distributed Energy Resource Aggregation Ramp Rate.

(iii) **Demand Response Distributed Energy Resource Aggregation Start-Up Time.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve its Minimum Deviation within the offered Demand Response Distributed Energy Resource Aggregation Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Distributed Energy Resource Aggregation Notification Time.

(iv) **Demand Response Distributed Energy Resource Aggregation Notification Time.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to start deviating demand within its offered Demand Response Distributed Energy Resource Aggregation Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Distributed Energy Resource Aggregation was not previously deviating demand.

(v) CLAIM10. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) CLAIM30. The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5

(d)(e) To conduct an audit based upon historical data, the ISO shall:

- (i) Obtain data through random sampling of generator, ~~or Demand Response Resource,~~ Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions; or
- (ii) Obtain data through continual monitoring of generator, ~~or Demand Response Resource,~~ Demand Response Distributed Energy Resource Aggregation performance in response to Dispatch Instructions.

~~(e)~~(f) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset, ~~or Demand Response Resource,~~ Demand Response Distributed Energy Resource Aggregation to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset, ~~or Demand Response Resource,~~ Demand Response Distributed Energy Resource Aggregation for the parameters being audited.

~~(f)~~(g) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

- (i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.
- (ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

~~(g)~~(h) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer, Baseline Deviation Offer, or other operating parameter values that are not representative of the actual capability of the Generator Asset, ~~or Demand Response Resource,~~ or Demand Response Distributed Energy Resource Aggregation, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

~~(h)~~(i) In the event that a Generator Asset, ~~or Demand Response Resource,~~ or Demand Response Distributed Energy Resource Aggregation has had a parameter value restricted:

- (i) The Market Participant may submit a restoration plan to the ISO to restore that parameter.

The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and

4.Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

- 1.Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
- 2.Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
- 3.Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

- (i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.
- (ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or
 - (iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

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

III.1.7.2 **[Reserved.]**

III.1.7.3 **Agents.**

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

III.1.7.4 **[Reserved.]**

III.1.7.5 **Transmission Constraint Penalty Factors.**

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

III.1.7.6 **Scheduling and Dispatching.**

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

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

- (i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.
 - (ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.
 - (iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.
- (c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.
- (d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

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

III.1.7.10 Other Transactions.

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

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

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
 - (i) Based upon review of historical data for non-intermittent daily cycle hydro.
 - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
 - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability

Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

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

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

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

III.1.7.13 Seasonal DECR Audit Value.

- (a) A Seasonal DECR Audit Value must be established and maintained for all Distributed Energy Capacity Resources. A summer Seasonal DECR Audit Value is established for use from June 1 through September 30 and a winter Seasonal DECR Audit Value is established for use from October 1 through May 31.
- (b) The Seasonal DECR Audit Value of Distributed Energy Capacity Resources is the sum of: the Seasonal Claimed Capabilities of Distributed Energy Resource Aggregations participating as a Generator Asset or a Settlement Only Distributed Energy Resource Aggregation; the Seasonal DR Audit value of a Distributed Energy Resource Aggregation participating as a Demand Response Resource; and the Seasonal DRDERA Audit values of the Demand Response Distributed Energy Resource Aggregations comprising the Distributed Energy Capacity Resource.

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

III.1.7.19.1 Eligibility.

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

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

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

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

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten

minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

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

III.1.7.19.2.1.2 Off-line Generator Assets.

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

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at

which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

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

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

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

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

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

Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

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

III.1.7.19.2.3 Demand Response Resources and Demand Response Distributed Energy Resource Aggregations.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2. The Demand Response Distributed Energy Resource Aggregation Ramp Rate used in

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

III.1.7.19.2.3.1 Dispatched.

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation). For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand

Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current ~~operational demand reduction~~ level, within thirty minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

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

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

III.1.7.20 Information and Operating Requirements.

- (a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, ~~or~~ demand reduction levels or baseline deviation levels of Generator Assets, DARDs, ~~or~~ Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations; change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

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

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

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

III.1.9.1.1 Cost Verification of Resource Offers.

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

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

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

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

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

III.1.9.1.2 Offer and Bid Caps.

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

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

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

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

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

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

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

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy

Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

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

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets, ~~or~~ Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers, ~~or~~ Demand Reduction Offers or Baseline Deviation Offers.

III.1.10.1A Energy Market Scheduling.

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

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

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

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

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

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

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

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

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

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

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

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

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

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

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

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

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

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

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

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

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

- (a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

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

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

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

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

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

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

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

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

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

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

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

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

(viii) Shall not include average avoided peak transmission or distribution losses in the baseline deviation quantity.

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

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

(xi) Shall specify a Maximum Deviation amount no greater than the sum of the Maximum Deviation Capabilities of the Demand Response Distributed Energy Resource Aggregation's operational Distributed Energy Resources.

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

(m) **Settlement Only Distributed Energy Resource Aggregation Supply Offers and/or Demand Bids** – Market Participants selling into the New England Markets from Settlement Only Distributed Energy Resource Aggregations and/or purchasing from the New England Markets for Settlement Only Distributed Energy Resource Aggregations may submit Supply Offers and /or Demand Bids, which will apply only to the Day-Ahead Energy Market. Such offers and/or bids must specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered and/or bid by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis

III.1.10.2 Pool-Scheduled Resources.

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

- (a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost, Deviation Cost and the specified operating characteristics, offered by Market Participants.
- (b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers, ~~and~~ Demand Reduction Offers and Baseline Deviation Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.
- (c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.
- (d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

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

III.1.10.4 External Resources.

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

III.1.10.5 Dispatchable Asset Related Demand.

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

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

III.1.10.6 Electric Storage

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

- (a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:
 - (i) comprise one or more storage facilities at the same point of interconnection;
 - (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
 - (iii) be directly metered;
 - (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
 - (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
 - (vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
 - (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to,

satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

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

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

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

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

- (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).
- (d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.
- (e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:
 - (i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.
 - (ii) A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.
 - (iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.
 - (iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.
 - (v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.
- (f) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

- (g) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (h) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)
- (i) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (j) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

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

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.
- (b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.
- (c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to

be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

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

III.1.10.7.A Coordinated Transaction Scheduling.

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

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

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An

Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

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

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

III.1.10.8 ISO Responsibilities.

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

other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule. (b)

Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

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

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

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, revisions to Baseline Deviation Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

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

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

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

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or

worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

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

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

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

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

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

III.1.10.10 Local Second Contingency Protection Resources

III.1.10.10.1 [Reserved.]

III.1.10.10.2 Day-Ahead and Real-Time Energy Market.

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

III.1.10.10.2.1 Special Constraint Resources.

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

III.1.10.10.3 [Reserved.]

III.1.11 Dispatch.

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

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the

Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, [Baseline Deviation Offer](#) or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

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

III.1.11.3 Dispatchable Resources.

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

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

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

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable

timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

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

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

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

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) ~~Settlement Only Resources are not eligible to be DNE Dispatchable Generators.~~

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

~~(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.~~

~~(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.~~

~~(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.~~

All wind and hydro Intermittent Power Resources are required to be DNE Dispatchable Generators, with the exception of wind and hydro Intermittent Power Resources with an injection capability of less than 5 MW that are connected through transmission facilities rated at less than 115 kV. A Distributed Energy Resource Aggregation is required to be a DNE Dispatchable Generator if it 1) consists entirely of wind or hydro Intermittent Power Resources or a combination of wind and hydro Intermittent Power Resources, and 2) participates as a Generator Asset.

(i) A Market Participant may elect to have a wind or hydro Intermittent Power Resource with an injection capability less than 5 MW that is connected through transmission facilities rated at less than 115 kV be a DNE Dispatchable Generator.

(ii) A Market Participant may elect to have a hydro Intermittent Power Resource or a Distributed Energy Resource Aggregation consisting entirely of hydro Intermittent Power Resources and participating as a Generator Asset be a DDP Dispatchable Resource if it is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range.

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

III.1.11.4 Emergency Condition.

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

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

- (a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.
- (b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redclarations must be updated throughout the Operating Day to reflect actual operating capabilities.
- (c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

- (i) at least once every 30 seconds: wind speed, and wind direction;
- (ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;
- (iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

- (iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

- (i) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, irradiance, wind speed, and wind direction;
- (ii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and
- (iii) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

- (a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

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

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

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

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

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which

shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, ~~or~~ Interruption Cost, or Deviation Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time, ~~or~~ Minimum Reduction Time or Minimum Deviation Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time, ~~or~~ Minimum Reduction Time or Minimum Deviation Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed \$2,000/MWh.

- (a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.
- (b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.
- (c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.
- (d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

(f) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has not satisfied its Minimum Deviation Time, its energy offer shall be increased by the Deviation Cost divided by the product of the Maximum Deviation and the Minimum Deviation Time.

(g) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has satisfied its Minimum Deviation Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the effect on transmission losses caused by

the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

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

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

III.2.6 Calculation of Nodal Day-Ahead Prices.

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

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional

increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset's Economic Maximum Limit, and demand reduction at the Demand Response Resource's Maximum Reduction, and baseline deviation at the Demand Response Distributed Energy Resource Aggregation's Maximum Deviation, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;
- (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, Baseline Deviation Offers, or Increment Offer price cleared).

Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

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

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

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

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

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

- (a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.
- (b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.
- (c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.
- (d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.
- (e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.
- (f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.
- (g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

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

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

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to

avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

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

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	Reserve Constraint Penalty Factor
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	\$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	\$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	\$50/MWh

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

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

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

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website.

The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

- (i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;
 - (ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;
 - (iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;
 - (iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and
 - (v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.
- (b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

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

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

using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

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

III.2.9B Final Day-Ahead Energy Market Results

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

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

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

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

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

III.3 Accounting And Billing

III.3.1 Introduction.

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

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 or Baseline Deviation 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, Settlement Only Distributed Energy Resource Aggregations, Demand Response Distributed Energy Resource Aggregations, 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.

(vi) **Real-Time Demand Reduction Obligation for Demand Response Distributed Energy Resource Aggregations** – 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 a Demand Response Distributed Energy Resource Aggregation at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction provided by a Demand Response Distributed Energy Resource Aggregation are equal to the sum of the demand reductions produced by its Distributed Energy Resources, which is each Distributed Energy Resource's performance as calculated pursuant to Section III.6.5(d), except such performance will not include any incremental energy injections for each Distributed Energy Resource. Demand reductions are increased by average avoided peak distribution losses.

(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 and Demand Response Distributed Energy Resource Aggregations**

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(eb) and (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 and Demand Response Distributed Energy Resource Aggregations** – 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 and Demand Response Distributed Energy Resource Aggregations). 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.

(q) **Real-Time Energy Market Charge/Credit For Demand Response Distributed Energy Resource Aggregations** – 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 Distributed Energy Resource Aggregations. The charge or credit shall be equal to the sum of (1) 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; and (2) 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.

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 and Demand Response Distributed Energy Resource Aggregations), 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 a Demand Response Distributed Energy Resource Aggregation, the Metered Quantity For Settlement equals the sum of the demand reductions of each Distributed Energy Resource produced in response to a non-zero Dispatch Instruction, with the demand reduction for each Distributed Energy Resource calculated pursuant to Section III.6.5(d) except such performance will not include any incremental energy injections, and the hourly revenue quality meter data value apportioned over the five minute intervals in the hour in accordance with sub-section (f) below. If the Demand Response Distributed Energy Resource Aggregation provides five minute interval data, such data will be used in the Metered Quantity for Settlement calculation.

(e)(f) 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 and Distributed Energy Resources Associated with a Demand Response Distributed Energy Resource Aggregation

- (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 and for each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation. Individual Distributed Energy Resources with a Maximum Deviation Capability less than 10 kW and constituting a homogeneous population, as determined by the ISO, must aggregate their demand reduction and energy injection capability to achieve a Maximum Deviation Capability of at least 10 kW to report telemetry. The telemetry values shall measure: the real-time demand of Demand Response Assets as measured at their Retail Delivery Points; or the real-time demand and output of Distributed Energy Resources associated with a Demand Response Distributed

Energy Resource Aggregation as measured at their Retail Delivery Points and/or points of interconnection, and shall be reported to the ISO as an average value every five minutes. For a Demand Response Resource and a Demand Response Distributed Energy Resource Aggregation 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, which~~ 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 or a Distributed Energy Resource, 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 or a Distributed Energy Resources 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 or Distributed Energy Resource shall be excluded from the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation 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 or a Distributed Energy Resource. 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 or a Distributed Energy Resource 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, and Demand Response Distributed Energy Resource Aggregations 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, and Demand Response Distributed Energy Resource Aggregations 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, 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.6 Distributed Energy Resource Aggregations

A Distributed Energy Resource Aggregation may participate in the New England Markets as described below. A Distributed Energy Resource Aggregation must comply with all applicable registration, metering, and accounting rules in this section.

III.6.1 Participation Requirements

An aggregation of Distributed Energy Resources that satisfies the requirements of Section III.6 may participate in the New England Markets as a Distributed Energy Resource Aggregation. A Distributed Energy Resource Aggregation shall:

- (a) comprise one or multiple facilities at one or more points of interconnection or Retail Delivery Points;
- (b) have regulation capability, energy injection capability, or combined demand reduction capability and energy injection capability of at least 0.1 MW;
- (c) be metered in accordance with Section III.6.4;
- (d) be registered pursuant to Section III.6.7;
- (e) participate in the wholesale markets as, and subject to all requirements applicable to a Generator Asset, Alternative Technology Regulation Resource, Continuous Storage Facility, Binary Storage Facility, Demand Response Resource, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation;
 - i. A Distributed Energy Resource Aggregation may participate as a Continuous Storage Facility or Binary Storage Facility to the extent the Distributed Energy Resource Aggregation as a whole is able to comply with all the requirements of a Continuous Storage Facility or Binary Storage Facility as stated in Sections III.1.10.6(b) and (c) respectively, regardless of whether any or all of the individual Distributed Energy Resources comprising the Distributed Energy Resource Aggregation meet the definition of Energy Storage Facility as defined in Section III.1.10.6.
- (f) not be located in the metering domain of a Host Utility that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such Host Utility to host Distributed Energy Resource Aggregations; and
- (g) meet the locational rules specified Section III.6.2.

III.6.2 Locational Requirements

A Distributed Energy Resource Aggregation must meet the following locational requirements.

- (a) For a Distributed Energy Resource Aggregation participating as an Alternative Technology Regulation Resource or a Demand Response Resource, all associated Distributed Energy Resources shall be located in a single DRR Aggregation Zone.
- (b) For a Distributed Energy Resource Aggregation participating as a Generator Asset, Binary Storage Facility, Continuous Storage Facility, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation, all associated Distributed Energy Resources shall be located within both a single DRR Aggregation Zone and a single Host Utility metering domain.
- (c) A Distributed Energy Resource Aggregation shall be settled at the DRR Aggregation Zone Node price, except where a single Distributed Energy Resource or a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, in which case, they are prohibited from aggregating with facilities at other Nodes, and will be settled at the single transmission Node price, not at the DRR Aggregation Zone Node price.
- (d) The ISO shall determine that all of the Distributed Energy Resources in a Distributed Energy Resource Aggregation are located in the same DRR Aggregation Zone. For Distributed Energy Resources in a Distributed Energy Resource Aggregation with energy injection capability or demand reduction capability of 1 MW or greater, the ISO's determination shall be based on the Host Utility's evaluation of the transmission node that will serve the Distributed Energy Resource.

III.6.3 Distributed Energy Resource Size Requirements

Individual Distributed Energy Resources participating in a Distributed Energy Resource Aggregation must meet the following size requirements.

- ~~(a)~~ A Distributed Energy Resource with overall injection capability of 5 MW or greater that participates in the New England Markets through a Distributed Energy Resource Aggregation must participate as a single facility Distributed Energy Resource Aggregation and be modeled and priced at a single transmission Node.
- (a)
- (b) If a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at other Nodes. This group of Distributed Energy Resources may participate as a Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.
- (c) For a Distributed Energy Resource Aggregation with multiple Distributed Energy Resources participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, each

participating Distributed Energy Resource in the aggregation must have injection capability of less than 5 MW.

- (d) For a Distributed Energy Resource Aggregation participating as a Demand Response Resource, the size requirements in Section III.8 shall apply.
- (e) For a Distributed Energy Resource Aggregation participating as a Demand Response Distributed Energy Resource Aggregation, the size requirements in III.6.5(b) shall apply.
- (f) For a Distributed Energy Resource Aggregation participating as a Settlement Only Distributed Energy Resource Aggregation, the size requirements in III.6.6 shall apply.
- (g) For a Distributed Energy Resource Aggregation participating as an ATRR, the size requirements in Section III.14 shall apply.

III.6.4 Metering and Telemetry Requirements

Distributed Energy Resource Aggregations must meet the following metering and telemetry requirements.

- (a) Distributed Energy Resource Aggregations participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, must comply with the metering and telemetry requirements in Sections III.3.2.1 and III.3.2.2.
- (b) Distributed Energy Resource Aggregations participating as an Alternative Technology Regulation Resource must comply with the metering and telemetry requirements in Section III.14.2.
- (c) Distributed Energy Resource Aggregations participating as Demand Response Resources or Demand Response Distributed Energy Resource Aggregations must comply with the metering and telemetry requirements in Section III.3.2.2. The metering and communication equipment associated with each participating Distributed Energy Resource must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetering.
- (d) Metering for each Distributed Energy Resource participating in a Distributed Energy Resource Aggregation shall meet all applicable state and Host Utility requirements and be located at, a Retail Delivery Point, or point of interconnection as applicable. A Distributed Energy Resource's point of interconnection may be located behind a Retail Delivery Point to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration.
- (e) If a Distributed Energy Resource's point of interconnection is located behind a Retail Delivery Point it shall be reported such that its output or load does not impact the load reported for the Retail Delivery Point. A Distributed Energy Resource Aggregator may only propose a metering location behind a Retail Delivery Point if the Host Utility confirms in writing to the Distributed Energy Resource Aggregator that the appropriate metering and associated system upgrades are in place to support load and generation reporting and any necessary reconstitution. Proof of such

written confirmation from the Host Utility should be provided as part of the attestation as referenced in Section III.6.7(c)(i)2.

- (f) The Distributed Energy Resource Aggregator shall retain metering data for each participating Distributed Energy Resource for a period of six years for purposes of auditing.

III.6.5 Additional Requirements For Demand Response Distributed Energy Resource Aggregations

In addition to the rules applicable to all Distributed Energy Resource Aggregations, the following rules apply to Demand Response Distributed Energy Resource Aggregations. A Demand Response Distributed Energy Resource Aggregation allows Distributed Energy Resources with demand reduction capability, Distributed Energy Resources with energy injection capability and Distributed Energy Resources with energy withdrawal capability to participate in the wholesale markets as a single resource.

- (a) A Demand Response Distributed Energy Resource Aggregation must include Distributed Energy Resources with both demand reduction capability and energy injection capability and may include Distributed Energy Resources with energy withdrawal capability.
- (b) Size Requirements. Individual Distributed Energy Resources participating in a Demand Response Distributed Energy Resource Aggregation must meet the following size requirements:
- (i) An individual Distributed Energy Resource with a Maximum Deviation Capability or ability to inject greater than or equal to 5 MW may not be registered as a component of a Demand Response Distributed Energy Resource Aggregation if its maximum energy injection capability is greater than its Maximum Facility Load. Such a Distributed Energy Resource must be the only facility associated with a Demand Response Distributed Energy Resource Aggregation and shall be modeled and priced at the transmission Node.
- (ii) An individual Distributed Energy Resource with a Maximum Deviation Capability and maximum energy injection capability less than 5 MW may participate in a Demand Response Distributed Energy Resource Aggregation with other facilities located within the same DRR Aggregation Zone and metering domain. Such a Demand Response Distributed Energy Resource Aggregation shall be modeled and priced at the DRR Aggregation Zone Node.
- (iii) If a group of Distributed Energy Resources has a Maximum Deviation Capability of, or can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at another Node. This group of Distributed Energy Resources may participate as a Demand Response

Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

(c) Baseline, Offer Requirements and Related Threshold Requirements. For each Demand Response Distributed Energy Resource Aggregation:

- (i) The ISO shall establish a baseline for each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.2.
- (ii) The Distributed Energy Resource Aggregator shall submit a Baseline Deviation Offer pursuant to Section III.1.10.1A(l) that reflects the aggregation's ability to deviate from its normal operational level.
- (iii) Its Baseline Deviation Offer shall be subject to the Demand Reduction Threshold calculated pursuant to Section III.1.10.1A(f)
- (iv) It may inject energy outside of dispatch intervals, which will be settled consistent with the rules for Settlement Only Resources.
- (v) It may withdraw energy outside of dispatch intervals, which will be settled consistent with the rules for Load Assets.

(d) Performance Calculation. The ISO shall calculate a Demand Response Distributed Energy Resource Aggregation's performance when it is dispatched. Such performance shall be the sum of the performance of each constituent Distributed Energy Resource. The ISO shall calculate the performance of each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.4.

III.6.6 Additional Requirements For Settlement Only Distributed Energy Resource Aggregations

A Settlement Only Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that may include Distributed Energy Resources with non-dispatchable energy injection capability and/or non-dispatchable energy withdrawal capability. A Settlement Only Distributed Energy Resource Aggregation shall comply with all Market Rules applicable to Settlement Only Resources and the following additional rules.

- (a) A Settlement Only Distributed Energy Resource Aggregation may submit a Supply Offer and/or Demand Bid in the Day-Ahead Energy Market in accordance with the requirements in Section III.1.10.1A(m).
- (b) There is no maximum size limit for a Settlement Only Distributed Energy Resource Aggregation, provided each constituent Distributed Energy Resource would otherwise be eligible to register as a Settlement Only Resource pursuant to OP-14.

III.6.7 Coordination of Registration and Modification

The process of coordinating the registration and activation for participation in the New England Markets between the ISO, the Distributed Energy Resource Aggregator and the Host Utility, regardless of the participation model chosen, includes four stages: 1) Initial Notification of Intent to Register a Distributed Energy Resource Aggregation; 2) Eligibility Confirmation; 3) Registration and Activation; and 4) Updates to an Existing Distributed Energy Resource Aggregation Registration. Completion of the Distributed Energy Resource Aggregation registration process requires that the Distributed Energy Resource Aggregator, Host Utility (or its agent) and ISO meet the following requirements for each stage.

(a) Initial Notification

(i) Distributed Energy Resource Aggregator shall make an initial notification to both the ISO and the Host Utility (or the Host Utility's Agent) of its intent to register a Distributed Energy Resource Aggregation. Such notification shall include the information required by applicable ISO New England Manuals, including, but not limited to: the retail billing account(s) of the individual Distributed Energy Resource(s) participating in the aggregation, information regarding the location, anticipated size, technologies to be included, markets in which participation is planned, information required by the Host Utility Tariff and Terms and Conditions, and the participation model that the Distributed Energy Resource Aggregation intends to use for the Distributed Energy Resource Aggregation; interconnection agreement(s) for each participating Distributed Energy Resource, if required under state law; and an anticipated date to begin energy and/or ancillary service market participation.

(b) Eligibility Confirmation. The Host Utility (or its agent) shall review each Distributed Energy Resource's eligibility to participate in a Distributed Energy Resource Aggregation and confirm the Aggregator's eligibility to register the proposed Distributed Energy Resource Aggregation in the manner established in this subsection. The time period for such review shall begin when the Host Utility or its agent receives the initial notification from the Distributed Energy Resource Aggregator and shall not exceed 60 calendar days. The Host Utility (or its agent) shall provide written notice to the ISO and the Distributed Energy Resource Aggregator of the eligibility confirmation, in accordance with the eligibility criteria described in this subsection. The eligibility confirmation shall be provided by the Host Utility or its agent to the appropriate relevant electric retail regulatory authority upon request. If the ISO does not receive timely notification from the Host Utility or its agent, then the ISO will assume that the operation of the

Distributed Energy Resource will not have a material reliability and/or safety impact on the applicable distribution system and shall be eligible to register with the proposed Distributed Energy Resource Aggregation.

(c)

(i) In order to verify eligibility, the Host Utility or its agent shall, to the extent practicable based on the representations made by the Distributed Energy Resource Aggregator in the initial notification or through information otherwise in the Host Utility's (or its agent's) possession:

1. confirm that each Distributed Energy Resource's metered net consumption or injection of energy will not be included in another Load Asset (if the Distributed Energy Resource Aggregation includes load) or Generator Asset.
2. confirm, based on the representations made by the Distributed Energy Resource Aggregator that no individual Distributed Energy Resource (as identified by any retail billing account record of the Host Utility) is participating in a retail program that prohibits it from providing the requested service in New England Markets.
3. confirm based on the representations made by the Distributed Energy Resource Aggregator that the proposed operation of each Distributed Energy Resource as part of the proposed Distributed Energy Resource Aggregation has appropriate interconnection and/or operating agreements in place with the Host Utility applicable to its technology and size.
4. determine whether the Distributed Energy Resource Aggregation may pose significant risks, or may require further study to evaluate the potential significance of the risks, to the safe and reliable operation of the distribution system based on analysis of relevant risk factors, such as overloads, voltage, stability, short circuit interrupting capability, flicker, equipment operation frequency coordination, and contingency analysis.
5. consider whether the proposed operation of any Distributed Energy Resource participating in a proposed Distributed Energy Resource Aggregation, or the Distributed Energy Resource Aggregation as a whole, imposes a need for distribution system upgrades to avoid safety and reliability impacts and, if so, confirm that the Distributed Energy Resource Aggregator has self-certified that such upgrades have been completed or will be completed before the Distributed Energy Resource desired activation date.

6. confirm that all the Distributed Energy Resources are within the Host Utility's metering domain.
 7. confirm that the net injection and consumption capability of the Distributed Energy Resources participating in the Distributed Energy Resource Aggregation do not exceed the capabilities as authorized by any associated interconnection agreements.
- (ii) For a Distributed Energy Resource Aggregation connecting to a Host Utility that served less than or equal to 4 million MWh of load in the previous fiscal year, the Host Utility (or its agent) shall confirm that the Host Utility has opted to allow Distributed Energy Resource Aggregations to participate in wholesale markets.
 - (iii) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is eligible in full or in part, the Distributed Energy Resource Aggregator shall provide a finalized list to the ISO and the Host Utility (or its agent) of the Distributed Energy Resources that have been found to be eligible for participation in the Distributed Energy Resource Aggregation, the participation model that the Distributed Energy Resource Aggregation intends to use, and the New England Markets in which the Distributed Energy Resource Aggregation plans to participate.
 - (iv) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is not eligible in full or in part, the Host Utility (or its agent) shall provide a written notice to the ISO and the Distributed Energy Resource Aggregator describing the eligibility criteria that were not met for any Distributed Energy Resource.
 - (v) In the event the Host Utility (or its agent) confirms that a Distributed Energy Resource Aggregation has not fulfilled the requirements of this subsection to be activated for participation in the New England Markets, and the Distributed Energy Resource Aggregator disputes this confirmation, the Distributed Energy Resource Aggregation may seek dispute resolution in a process established by the relevant electric retail regulatory authority, if available, or if not available, in accordance with Section I.6 of the Tariff. Any disputes regarding whether the Distributed Energy Resource Aggregator has appropriate contractual rights to offer a Distributed Energy Resource as part of a Distributed Energy Resource Aggregation in the New England Markets shall be resolved in the manner established in such contract, or otherwise by a court of competent jurisdiction as applicable.
 - (vi) In the event the ISO determines that a Distributed Energy Resource Aggregation is ineligible to participate in the New England Markets for reasons that are not related to the

Host Utility (or its agent's) review, the Distributed Energy Resource Aggregator may seek resolution in accordance with Section I.6 of the Tariff.

(d) Registration/Activation

(i) In order to complete the registration and activation of a DERA the DER Aggregator shall:

1. Provide both the ISO and the Host Utility (or its agent) with a desired activation date, once eligibility has been confirmed.
2. Provide the information required by applicable ISO New England Manuals, as well as 1) an attestation, in a form prescribed by the ISO, stating that all participating Distributed Energy Resources are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements, and that the Distributed Energy Resource Aggregator retains the rights to offer the individual Distributed Energy Resource in New England Markets; and 2) confirmation in writing to the ISO and Host Utility (or its agent) that all Distributed Energy Resources in the Distributed Energy Resource Aggregation have been deemed eligible under subsection (b) of this section; and that the required metering and telemetry is in place, to meet the ISO requirements for participation in the planned markets.

(ii) Prior to activation, the ISO must receive confirmation from the Host Utility (or its agent) that the Distributed Energy Resource Aggregator has met all applicable requirements with respect to metering and telemetry to enable the Host Utility or Assigned Meter Reader to include the Distributed Energy Resource Aggregation's metering in the appropriate Load Asset and metering domain.

(iii) Distributed Energy Resources participating in a Distributed Energy Resource Aggregation may provide both retail and wholesale services to the extent such dual participation is allowed under state law or regulation, the Distributed Energy Resource Aggregator retains the rights to such services from the owner of the Distributed Energy Resource, and so long as the Distributed Energy Resource Aggregation is able to comply with all requirements under the ISO Tariff.

(e) Updates/Modifications to Existing Distributed Energy Resource Aggregation

(i) When a Distributed Energy Resource is added to or removed from an existing Distributed Energy Resource Aggregation, the Distributed Energy Resource Aggregator shall update

the Distributed Energy Resource Aggregation's registration information. Such updates shall include: the information required by applicable ISO New England Manuals, sufficient to confirm that any newly added Distributed Energy Resources are eligible for participation; notification to the ISO and the Host Utility (or its agent) by the Distributed Energy Resource Aggregator of any Distributed Energy Resource being removed from the aggregation; verification that any required metering is in place for the reconfigured Distributed Energy Resource Aggregation; and an updated list of participating Distributed Energy Resources and the updated performance capabilities of the aggregation to be reflected in the aggregation's registration information.

- (ii) The Host Utility (or its agent) shall have up to 60 days to confirm eligibility and review any impacts associated with Distributed Energy Resources that the Distributed Energy Resource Aggregator is proposing to add to or remove from an existing Distributed Energy Resource Aggregation.
- (iii) Changes to the Distributed Energy Resources participating in a Distributed Energy Resource Aggregation shall become effective in the manner stated in Manual M-RPA.

III.6.8 Operational Coordination

The responsibilities related to the coordination of operations of a Distributed Energy Resource Aggregation between the Distributed Energy Resource Aggregator, the ISO, and the Host Utility are as follows:

- (a) The Distributed Energy Resource Aggregator shall: operate Distributed Energy Resources in a manner consistent with the limitations and operating orders established by the Host Utility; confer with the applicable Host Utility on a periodic basis to ensure available distribution service exists to operate its Distributed Energy Resources consistent with its New England Market obligations; submit outage requests for each Distributed Energy Resource Aggregation as necessary and to the extent required by ISO Operating Documents, in order to reflect known distribution system constraints or limitations that reduce the overall capability of the Distributed Energy Resource Aggregation; as required, account for any known limitations of the distribution system to which the Distributed Energy Resources are connected in its Offer Data for the Distributed Energy Resource Aggregation including restrictions that have been placed directly on the Distributed Energy Resource Aggregation by the Host Utility in the form of an override of an ISO Dispatch

Instruction: determine a Distributed Energy Resource-level operating plan to be provided to the Host Utility for analysis, subject to the requirements of each Host Utility.

- (b) The Distributed Energy Resource Aggregator shall have a Designated Entity or Demand Designated Entity, as applicable, for each of its Distributed Energy Resource Aggregations in accordance with the provisions set forth in ISO Operating Procedures. Designated Entities and Demand Designated Entities for Distributed Energy Resource Aggregations shall comply with the requirements of each Host Utility and/or relevant electric retail regulatory authority as applicable.
- (c) In the event that the Host Utility identifies conditions on the distribution system that result in actual or anticipated limitations on the operation of individual Distributed Energy Resources or Distributed Energy Resource Aggregations, the Host Utility shall notify the relevant Distributed Energy Resource Aggregator as soon as practicable.
- (d) The Host Utility may temporarily override the ISO's dispatch of a Distributed Energy Resource Aggregation. Such override shall only occur in circumstances where needed to maintain the reliable and safe operation of the distribution system.
- (e) Failure of a Distributed Energy Resource Aggregation to follow an ISO Dispatch Instruction due to a Host Utility override does not excuse the Distributed Energy Resource Aggregator from any applicable charges (including any penalties) to which the Distributed Energy Resource Aggregator is subject under the terms of the Tariff.
- (a) The ISO shall coordinate with the applicable Host Utility to avoid conflicting operational directives, which may include but is not limited to sharing Day-Ahead Energy Market results and Real-Time Dispatch Instructions. ~~III.6~~ **Local Second Contingency Protection Resources**
- (b) ~~_____~~
- (c) ~~III.6.1~~ **[Reserved.]**
- (d) ~~_____~~
- (e) ~~III.6.2~~ **Day Ahead and Real Time Energy Market.**
- (f) ~~When establishing operating schedules, the ISO will select and identify Local Second Contingency Protection Resources on a not unduly discriminatory basis in accordance with the procedures defined in the ISO New England Manuals. Appendix A will determine which, if any, Supply Offers will be adjusted. The ISO will also record, in an auditable log, the reason the Resource was selected.~~
- (g) ~~_____~~
- (h) ~~III.6.2.1~~ **Special Constraint Resources.**

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

~~(j)~~

~~(k) **III.6.3** [Reserved.]~~

~~(l)~~

~~(m)~~

~~(n)~~

~~(o)~~

III.9 Forward Reserve Market

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

III.9.1 Forward Reserve Market Timing.

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

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

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

III.9.2 Forward Reserve Requirements.

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

III.9.2.1 System Forward Reserve Requirements.

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

- (i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.
- (ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate

that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

- (iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.
- (iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

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

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

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

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response

Resource or Demand Response Distributed Energy Resource Aggregations the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource or Demand Response Distributed Energy Resource Aggregations as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

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

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

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource or Demand Response Distributed Energy Resource Aggregations.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregations the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregations the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

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

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

III.9.3 Forward Reserve Auction Offers.

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

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

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

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

**III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation
Publication and Correction.**

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

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

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

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

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

will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

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

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

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, and Demand Response Distributed Energy Resource Aggregations in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

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

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation which has not been dispatched, it must be a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;

(vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;

(vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;

(viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

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

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:
 - (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;
 - (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.
2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
 - (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;
 - (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.
3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.
4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.
5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:
 - a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;
 - b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

- c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or
- d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.
- e) For Demand Response Distributed Energy Resource Aggregations, the ratio of (i) the sum of the applicable Deviation Cost and the baseline deviation cost to Minimum Deviation used in the Real-Time dispatch of the Demand Response Distributed Energy Resource Aggregation in the Operating Day to (ii) the maximum total hourly Deviation Cost and baseline deviation cost to Minimum Deviation submitted for the Demand Response Distributed Energy Resource Aggregation for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

- 6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:
 - a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.

- b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.
- c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market

Participant. The ISO will normally perform the audit, at any time during the Forward Reserve Delivery Period, within five Business Days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five Business Day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10} \left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n \right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

- (i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.
- (ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.
- (iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.
- (iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.
- (v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the

increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources or Demand Response Distributed Energy Resource Aggregations for an hour by offering the capability into the Real-Time Energy Market by submitting -Demand Reduction Offers or Baseline Deviation Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

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

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

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

- (a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.
- (b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.
- (c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on

meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) **Generator Assets and Dispatchable Asset Related Demands** – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

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

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

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

where:

StartUp = cold Start-Up Fee.
NoLoad = No-Load Fee.
EnergyOffer_i = the Energy offer price for
Energy offer block *i*.
EcoMax = Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the

applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) Demand Response Resources and Demand Response Distributed Energy Resource

Aggregations – Qualifying megawatts for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have not been dispatched and Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation that has not been dispatched: is the amount of capability equal to or below the Maximum Deviation for the Demand Response Distributed Energy Resource Aggregation offered at or above the Forward Reserve Threshold Price. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Distributed Energy Resource Aggregations that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Baseline Deviation Offer price and a pro-rated amount of the Deviation Cost as defined below.

A Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation that has not been dispatched must offer its capability so that the following holds:

where:

Interruption Cost = Interruption Cost.

Deviation Cost = Deviation Cost

EnergyOffer_i = Demand Reduction Offer price or *Baseline Deviation* for
Energy offer block *i*.

Max-Red = Maximum Reduction x 1 hour.

MaxDev = Maximum Deviation x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation which has been dispatched: is the capability that is less than or equal to the Maximum Deviation and greater than the Minimum Deviation that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Distributed Energy Resource Aggregation. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Distributed Energy Resource Aggregation which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

- (a) Forward Reserve Delivered Megawatts for an off-line Generator Asset are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:
 - (i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

- (b) Forward Reserve Delivered Megawatts for an on-line Generator Asset are calculated in megawatts for each hour for each Reserve Zone as the minimum of:
 - (i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

- (c) Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:
 - (i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,
 - (ii) Forward Reserve Assigned Megawatts, or

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

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

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

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

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer or in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer,

(ii) Forward Reserve Assigned Megawatts, or

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

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

- (i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate of that Resource, as applicable,
- (ii) Forward Reserve Assigned Megawatts, or
- (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

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

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

- (i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.
- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.
- (iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

(i) In determining Forward Reserve Delivered Megawatts for a Demand Response Distributed Energy Resource Aggregation the portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be increased by average avoided peak distribution losses, limited as described below.

- (i) The ISO will assume that Demand Response Distributed Energy Resource Aggregations first reduce their net load from the electricity system before providing additional energy injection.

- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Distributed Energy Resource Aggregation can reduce from the electric system based on the net load of its constituent Distributed Energy Resources.
- (iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with energy injection will be capped at the remaining energy injection capability of the Demand Response Distributed Energy Resource Aggregation.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

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

- (a) Forward Reserve Failure-to-Reserve Megawatts:
 - (i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:
 - (1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and
 - (2) Zero.
 - (ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

- (1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and
- (2) Zero.

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

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

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;

- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts:**

- (i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:
 - (1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;
 - (2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit, ~~or~~ Minimum Reduction or Minimum Deviation, whichever is greater, (ii) the Resource's CLAIM10, and (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources and Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 10 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction or baseline deviation at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial demand reduction or baseline deviation at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

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

Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

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

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit, ~~or~~ Minimum Reduction or Minimum Deviation, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources or Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

- (iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

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

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

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

Where:

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

III.9.7.3 Known Performance Limitations.

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

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

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

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

III.9.8 Forward Reserve Credits.

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

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

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

(b) $FRACP_{Zone}$ is defined as the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR = Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to:

applicable monthly $FRACP_{Zone}$ for TMNSR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

applicable monthly $FRACP_{Zone}$ for TMOR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.

The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

- (i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or
- (ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

- (i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

- (ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

- (i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

- (i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a zonal Forward Reserve requirement greater than zero, and
- (ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Settlement for Real-Time Reserves

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. 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.10.1 Reserve Quantity For Settlement

Each Resource receiving a Real-Time Reserve Designation pursuant to Section III.1.7.19 shall receive, for each settlement interval, a Reserve Quantity For Settlement. The Reserve Quantity For Settlement shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve. The Reserve Quantity For Settlement values will equal the corresponding Real-Time Reserve Designation values, adjusted downward after the fact to account for actual reserve capability based on Metered Quantity For Settlement.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time. Demand Response Resource credits will be limited as described in Section III.9.6.5(h).

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market

Participant's Resource specific Reserve Quantity For Settlement for TMNSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMOR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

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

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT_CHRG_RT}_i]$$

Where:

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

Reserve Charge Allocation MW = Market Participant *k*'s Real Time Load Obligation in Load Zone *i* adjusted for the Reserve Quantity For Settlement MWs of Market Participant *k*'s Dispatchable Asset Related Demand MWs in Load Zone *i*.

$RT_CHRG_RT_i = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] \times [RT_P_RATIO]$ for TMSR, TMNSR, or TMOR, as applicable.

$RT_P_WTD_LD_OB = \sum [Reserve\ Charge\ Allocation\ MW_{si}] \times [P_RATIO_i]$ for TMSR, TMNSR or TMOR, as applicable;

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

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

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

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each settlement interval such that a Market Participant will not receive compensation for Real-Time Operating Reserve MWs provided to satisfy a Forward Reserve Obligation.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

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

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Reserve Quantity For Settlement (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

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

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

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

Clean Tariff

Effective November 1, 2026

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, 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.

Baseline Deviation Offer is an offer by a Market Participant with a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or inject additional energy.

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); (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 each hour); and (8) with respect to Baseline Deviation Offers administered by the ISO, a quantity of reduced demand or additional energy injection with a related price (Baseline Deviation Offers may contain multiple sets of quantity and price pairs for each hour).

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

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

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

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, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

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 or a Distributed Energy Resource associated

with a Demand Response Distributed Energy Resource Aggregation, 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.

Curtailement 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 Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

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 Distributed Energy Resource Aggregation Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy.

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 Distributed Energy Resource Aggregation Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Distributed Energy Resource Aggregation can reduce demand and/or inject additional energy.

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.

Demand Response Distributed Energy Resource Aggregation Start-Up Time is the period of time between the time a Demand Response Distributed Energy Resource Aggregation starts reducing demand and/or injecting energy at the conclusion of the Demand Response Distributed Energy Resource Aggregation Notification Time and the time the resource can reach its Minimum Deviation 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, Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation dispatched by the ISO in accordance with the asset's Offer Data.

Deviation Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Distributed Energy Resource Aggregation is scheduled or dispatched in the New England Markets to reduce demand and/or provide additional energy injection.

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 or Demand Response Distributed Energy Resource Aggregations, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, Demand Reduction Offer or Baseline Deviation 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, Demand Response Distributed Energy Resource Aggregation, 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, Regulation Service Offer or Baseline Deviation 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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal,

regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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, Baseline Deviation 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, Baseline Deviation 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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 Demand Response Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; (ii) Minimum Time Between Deviations does not exceed one hour; (iii) Demand Response Distributed Energy Resource Aggregation Start-Up Time plus Demand Response Distributed Energy Resource Aggregation 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.

Initial State of Charge is the State of Charge that an Electric Storage Facility offers at the start of hour one of the Day-Ahead Energy Market.

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 or an aggregation of wind, solar, run of river hydro and other renewable resources 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, Demand Reduction Offers or Baseline Deviation 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 Deviation is the maximum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or provide energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer

Maximum Deviation Capability is an estimate of the maximum demand reduction and/or energy injection that a Distributed Energy Resource comprising a Demand Response Distributed Energy Resource Aggregation can deliver, as measured at the Retail Delivery Point and/or Point-of-Interconnection

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 or that a Demand Response Distributed Energy Resource Aggregation 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.

Maximum State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, above which the ISO shall not schedule the Electric Storage Facility to receive electricity from the grid.

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 (MG TSA) 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), MG TSA 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 Deviation is the minimum available baseline deviation, in MW, of a Demand Response Distributed Energy Resource Aggregation that a Market Participant offers to reduce demand and/or

provide additional energy injection in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer.

Minimum Deviation Time is the minimum number of hours of baseline deviation at or above the Minimum Deviation for which the ISO must dispatch a Demand Response Distributed Energy Resource Aggregation to reduce demand and/or provide additional energy injection.

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 State of Charge is the megawatt-hour value of stored energy, submitted by an Electric Storage Facility as part of its Offer Data for a given hour of the Day-Ahead Energy Market, below which the ISO shall not schedule the Electric Storage Facility to inject electricity to the grid.

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 Time Between Deviations is the number of hours that must elapse after a Demand Response Distributed Energy Resource Aggregation has received a Dispatch Instruction to stop reducing demand and/or injecting additional energy before the Demand Response Distributed Energy Resource Aggregation can achieve its Minimum Deviation after receiving a Dispatch Instruction to start reducing demand and/or injecting additional energy.

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, New Demand Capacity Resource, or New Distributed Energy 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 Distributed Energy Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.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 Distributed Energy Capacity Resource Show of Interest Form is described in Section III.13.1.4A.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, Demand Response Resource, and Demand

Response Distributed Energy Resource Aggregation operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, Demand Response Resources and Demand Response Distributed Energy Resource Aggregations 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 or a Baseline Deviation 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 or a Fast Start Demand Response Distributed Energy Resource Aggregation that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer or a Baseline Deviation 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 or a Fast Start Demand Response Distributed Energy Resource Aggregation 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, Settlement Only Distributed Energy Resource Aggregation, the energy injection and/or energy withdrawal portion of a Demand Response Distributed Energy

Resource Aggregation, 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. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Distributed Energy Resource Aggregation for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Deviation Time does not exceed one hour; and (ii) Demand Response Distributed Energy Resource Aggregation Notification Time plus Demand Response Distributed Energy Resource Aggregation 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 an 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 or, revised Baseline Deviation Offers associated with Demand Response Distributed Energy Resource Aggregation.

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, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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.

Round-Trip Efficiency is a percentage expressing the megawatt-hours of energy that an Electric Storage Facility injects onto the grid per megawatt-hour of energy it receives from the grid.

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 and Demand Response Distributed Energy Resource Aggregations 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 Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

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 of Charge is the total quantity of megawatt-hours available to be injected by an Electric Storage Facility onto the grid.

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.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 **[Reserved.]**

III.1.3.2 **[Reserved.]**

III.1.3.3 **[Reserved.]**

III.1.4 **Requirements for Certain Transactions.**

III.1.4.1 **ISO Settlement of Certain Transactions.**

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 **Transactions Subject to Requirements of Section III.1.4.**

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as “Section III.1.4 Transactions,” and individually as a “Section III.1.4 Transaction.” Transactions that conform to the standards are referred to collectively as “Section III.1.4 Conforming Transactions,” and individually as a “Section III.1.4 Conforming Transaction.”

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

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

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

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

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

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

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

III.1.5.1.2 Establish Claimed Capability Audit.

- (a) An Establish Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (b) The time and date of an Establish Claimed Capability Audit shall be unannounced.
- (c) For a newly commercial Generator Asset or Settlement Only Distributed Energy Resource Aggregation:
 - (i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:
 1. Non-intermittent daily cycle hydro;
 2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and

3. Intermittent Generator Assets or intermittent Settlement Only Distributed Energy Resource Aggregations

- (ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (d) For Generator Assets with an Establish Claimed Capability Audit value:
- (i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
 - (ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.
 - (iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
 - (iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset or the sum of the maximum energy injection capabilities of the Settlement Only Distributed Energy Resource Aggregation's constituent Distributed Energy Resources.
- (f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.
- (g) To conduct an Establish Claimed Capability Audit, the ISO shall:
- (i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit or the Settlement Only Distributed Energy Resource Aggregation's net output to increase from the current operating level to its maximum energy injection capability.

- (ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.
- (h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage)	2
Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage	2
Hydro-Conventional Run of River	2
Hydro-Conventional Weekly	2
Wind	2
Photovoltaic	2
Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

- (i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2 (h) or a Settlement Only Distributed Energy Resource Aggregation consisting of a single technology type not listed in Section III.1.5.1.2 (h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

- (a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset or Settlement Only Distributed Energy Resource Aggregation.
- (b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets and Settlement Only Distributed Energy Resource Aggregation except:
 - (i) Non-intermittent daily hydro; and
 - (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).
- (c) An Established Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's or Settlement Only Distributed Energy Resource Aggregation's Seasonal Claimed Capability Audit obligation.
- (d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once every Capability Demonstration Year;
 - (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.
- (e) A winter Seasonal Claimed Capability Audit must be conducted:
 - (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
 - (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
 - (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.
 - (ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset or Settlement Only Distributed Energy Resource Aggregation, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.
- (f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset or Settlement Only Distributed Energy Resource Aggregation for the audit time period and submitting to the ISO operational data that meets the following requirements:

- (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
- (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.
- (g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.
- (h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.
- (i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.
- (j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage)	2
Hydraulic Turbine-Other	
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

- (k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;
 - (ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and
 - (iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.
- (l) A Generator Asset or Settlement Only Distributed Energy Resource Aggregation that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset or Settlement Only Distributed Energy Resource Aggregation's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:
 - (i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;
 - (ii) Retain the current Seasonal Claimed Capability Audit value for the season; and
 - (iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.
- (m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset or Settlement Only Distributed Energy Resource Aggregation to perform

a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset or Settlement Only Distributed Energy Resource Aggregation during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

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

III.1.5.1.3.1 Seasonal DR Audits.

- (a) A Seasonal DR Audit may be performed only by a Demand Response Resource.
- (b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:
 - (i) At least once every Capability Demonstration Year;

- (ii) During the months of December through March.
- (e) A Seasonal DR Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or
 - (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DR Audit:
 - (i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.
- (h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.
- (i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.
- (j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

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

III.1.5.1.3.2 Seasonal DRDERA Audits.

- (a) A Seasonal DRDERA Audit may be performed only for a Demand Response Distributed Energy Resource Aggregation.
- (b) A Seasonal DRDERA Audit shall be performed for 12 contiguous five-minute intervals.
- (c) A summer Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of April through November;
- (d) A winter Seasonal DRDERA Audit must be conducted by all Demand Response Distributed Energy Resource Aggregations:
 - (i) At least once every Capability Demonstration Year;
 - (ii) During the months of December through March.
- (e) A Seasonal DRDERA Audit may be performed either:
 - (i) At the request of a Market Participant as described in subsection (f) below; or

- (ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.
- (f) If a Market Participant requests a Seasonal DRDERA Audit:
 - (i) The ISO shall perform the Seasonal DRDERA Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.
 - (ii) The ISO shall initiate the Seasonal DRDERA Audit by issuing a Dispatch Instruction ordering the Demand Response Distributed Energy Resource Aggregation to its Maximum Deviation.
 - (iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.
 - (iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Baseline Deviation Offer parameters, to its Maximum Deviation.
 - (v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.
- (g) If the Seasonal DRDERA Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.2 and:
 - (i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DRDERA Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.
 - (ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DRDERA Audit.
 - (iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Distributed Energy Resource Aggregation Notification Time.
 - (iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DRDERA Audit as provided in this Section III.1.5.1.3.2 may be used to fulfill the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.
- (h) An ISO-Initiated Claimed Capability Audit fulfills the Seasonal DRDERA Audit obligation of a Demand Response Distributed Energy Resource Aggregation.
 - (i) Each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation is evaluated during the Seasonal DRDERA Audit of the Demand Response Distributed Energy Resource Aggregation.

- (j) Any Distributed Energy Resource on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.
- (k) The Seasonal DRDERA Audit value (summer or winter) of a Demand Response Distributed Energy Resource Aggregation resulting from the Seasonal DRDERA Audit shall be the sum of the load reductions demonstrated during the audit by each of the Demand Response Distributed Energy Resource Aggregation's constituent Distributed Energy Resources plus the energy injected by the Demand Response Distributed Energy Resource Aggregation during the audit period.
- (l) If a Distributed Energy Resource is added to or removed from a Demand Response Distributed Energy Resource Aggregation between audits, the Demand Response Distributed Energy Resource Aggregation's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Distributed Energy Resource, such that at any point in time the summer or winter Seasonal DRDERA Audit value of a Demand Response Distributed Energy Resource Aggregation shall equal the sum of the most recent valid like-season audit values of its constituent Distributed Energy Resources.
- (m) The Seasonal DRDERA Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

The summer or winter audit value of a Distributed Energy Resource shall be set to zero at the end of the Capability Demonstration Year if the Distributed Energy Resource did not perform a Seasonal DRDERA Audit for that season as part of a Demand Response Distributed Energy Resource Aggregation during that Capability Demonstration Year.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

- (a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.
- (b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource, shall replace either the summer or winter Seasonal DRDERA Audit value for a Demand Response Distributed Energy Resource Aggregation, and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset or Settlement Only Distributed Energy Resource Aggregation, normalized for temperature and steam exports, except:
 - (i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability or equivalent interconnection agreements for that resource.

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

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	Claimed Capability Audit Duration (Hrs)
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource or Demand Response Distributed Energy Resource Aggregations	1
Distributed Energy Resource Aggregation Containing More Than One Technology Type	2

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

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer, Baseline Deviation Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregation to provide real-time energy or reserves.

- (b) Generator Asset audits shall be performed using the following methods for the relevant parameter:
- (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.
 - (viii) **Dual Fuel Capability.** A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).
- (c) Demand Response Resource audits shall be performed using the following methods:
- (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.
 - (iv) **Demand Response Resource Notification Time.** The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response

Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

- (v) **CLAIM10.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (d) Demand Response Distributed Energy Resource Aggregation audits shall be performed using the following methods:
- (i) **Maximum Deviation.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve the current offered Maximum Deviation value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Distributed Energy Resource Aggregation Ramp Rate.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Distributed Energy Resource Aggregation Ramp Rate.
 - (iii) **Demand Response Distributed Energy Resource Aggregation Start-Up Time.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to achieve its Minimum Deviation within the offered Demand Response Distributed Energy Resource Aggregation Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Distributed Energy Resource Aggregation Notification Time.
 - (iv) **Demand Response Distributed Energy Resource Aggregation Notification Time.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to start deviating demand within its offered Demand Response Distributed Energy Resource Aggregation Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Distributed Energy Resource Aggregation was not previously deviating demand.
 - (v) **CLAIM10.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.
 - (vi) **CLAIM30.** The Demand Response Distributed Energy Resource Aggregation shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.
- (e) To conduct an audit based upon historical data, the ISO shall:

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

The restoration plan shall:

 1. Provide an explanation of the discrepancy;
 2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
 3. Indicate the timeline for completing the restoration; and

4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

- (i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.
- (ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

- (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.
- (g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:
 - (i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;
 - (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or
 - (iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.
- (h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

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

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

III.1.7 **General.**

III.1.7.1 **Provision of Market Data to the Commission.**

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

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

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

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

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

III.1.7.6 Scheduling and Dispatching.

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

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

- (i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.
 - (ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.
 - (iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.
- (c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.
- (d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

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

III.1.7.10 Other Transactions.

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

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

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
 - (i) Based upon review of historical data for non-intermittent daily cycle hydro.
 - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
 - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability

Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

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

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

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

III.1.7.13 Seasonal DECR Audit Value.

- (a) A Seasonal DECR Audit Value must be established and maintained for all Distributed Energy Capacity Resources. A summer Seasonal DECR Audit Value is established for use from June 1 through September 30 and a winter Seasonal DECR Audit Value is established for use from October 1 through May 31.
- (b) The Seasonal DECR Audit Value of Distributed Energy Capacity Resources is the sum of: the Seasonal Claimed Capabilities of Distributed Energy Resource Aggregations participating as a Generator Asset or a Settlement Only Distributed Energy Resource Aggregation; the Seasonal DR Audit value of a Distributed Energy Resource Aggregation participating as a Demand Response Resource; and the Seasonal DRDERA Audit values of the Demand Response Distributed Energy Resource Aggregations comprising the Distributed Energy Capacity Resource.

- (c) The Seasonal Claimed Capability of a Settlement Only Distributed Energy Resource is:
 - a. Based upon review of historical data for non-intermittent daily cycle hydro.
 - b. The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities as reflected in hourly revenue metering data.
 - c. For all other Settlement Only Distributed Energy Resources, the minimum of: (1) the Settlement Only Distributed Energy Resource's current Establish Claimed Capability Audit value and (2) the Settlement Only Distributed Energy Resource's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

The Seasonal DRDERA Audit value for Distributed Energy Resource Aggregations participating as Demand Response Distributed Energy Resource Aggregations is the value of the audit for the aggregation performed pursuant to Section III.1.5.1.3.2.

III.1.7.14 **[Reserved.]**

III.1.7.15 **[Reserved.]**

III.1.7.16 **[Reserved.]**

III.1.7.17 **Operating Reserve.**

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

III.1.7.18 **Ramping.**

A Generator Asset, Dispatchable Asset Related Demand, Demand Response Distributed Energy Resource Aggregation, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to potential referral under Section III.A.19.

III.1.7.19 **Real-Time Reserve Designation.**

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

III.1.7.19.1 Eligibility.

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

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

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

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

- (a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten

minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

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

III.1.7.19.2.1.2 Off-line Generator Assets.

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

- (a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at

which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

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

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

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

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

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

Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

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

III.1.7.19.2.3 Demand Response Resources and Demand Response Distributed Energy Resource Aggregations.

For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2. The Demand Response Distributed Energy Resource Aggregation Ramp Rate used in

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

III.1.7.19.2.3.1 Dispatched.

- (a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within ten minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation). For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.
- (b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within ten minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation).
- (c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource or as the increase in demand reduction and/or energy injection that the Demand

Response Distributed Energy Resource Aggregation could achieve, relative to the estimated current operational level, within thirty minutes given its Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate (and in no case greater than its Maximum Reduction or Maximum Deviation) minus the Ten-Minute Spinning Reserve quantity calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

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

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

III.1.7.20 Information and Operating Requirements.

- (a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, demand reduction levels or baseline deviation levels of Generator Assets, DARDs, Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations; change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

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

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

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

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

III.1.9.1.1 Cost Verification of Resource Offers.

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

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

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

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

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

III.1.9.1.2 Offer and Bid Caps.

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

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

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

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

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

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

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

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy

Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

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

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets, Demand Response Resources, or Demand Response Distributed Energy Resource Aggregations with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers, Demand Reduction Offers or Baseline Deviation Offers.

III.1.10.1A Energy Market Scheduling.

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

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

(b) **External Transactions** – All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

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

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

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers** – Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

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

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

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

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

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

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

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

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

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

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

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

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

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

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

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

- (a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

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

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

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

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

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

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

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

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

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

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

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

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

(viii) Shall not include average avoided peak transmission or distribution losses in the baseline deviation quantity.

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

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

(xi) Shall specify a Maximum Deviation amount no greater than the sum of the Maximum Deviation Capabilities of the Demand Response Distributed Energy Resource Aggregation's operational Distributed Energy Resources.

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

(m) **Settlement Only Distributed Energy Resource Aggregation Supply Offers and/or Demand Bids** – Market Participants selling into the New England Markets from Settlement Only Distributed Energy Resource Aggregations and/or purchasing from the New England Markets for Settlement Only Distributed Energy Resource Aggregations may submit Supply Offers and /or Demand Bids, which will apply only to the Day-Ahead Energy Market. Such offers and/or bids must specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered and/or bid by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis

III.1.10.2 Pool-Scheduled Resources.

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

- (a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost, Deviation Cost and the specified operating characteristics, offered by Market Participants.
- (b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers, Demand Reduction Offers and Baseline Deviation Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.
- (c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.
- (d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

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

III.1.10.4 External Resources.

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

III.1.10.5 Dispatchable Asset Related Demand.

- (a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.
- (b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:
 - (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
 - (ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
 - (iii) abide by the ISO maintenance coordination procedures; and
 - (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

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

- (a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:
 - (i) comprise one or more storage facilities at the same point of interconnection;
 - (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
 - (iii) be directly metered;
 - (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
 - (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
 - (vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
 - (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to,

satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

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

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

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

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

- (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).
- (d) In clearing the Day-Ahead Energy Market, the ISO will respect Electric Storage Facility Initial State of Charge, Round Trip Efficiency, Maximum State of Charge, and Minimum State of Charge.
- (e) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:
 - (i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.
 - (ii) A storage facility's charging energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging energy.
 - (iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.
 - (iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.
 - (v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.
- (f) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

- (g) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.
- (h) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)
- (i) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.
- (j) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

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

- (a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.
- (b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.
- (c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to

be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

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

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

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

III.1.10.7.A Coordinated Transaction Scheduling.

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

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

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An

Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

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

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

III.1.10.8 ISO Responsibilities.

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

other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule. (b)

Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

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

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

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, revisions to Baseline Deviation Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

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

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

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

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or

worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

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

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

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

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

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

III.1.10.10 Local Second Contingency Protection Resources

III.1.10.10.1 [Reserved.]

III.1.10.10.2 Day-Ahead and Real-Time Energy Market.

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

III.1.10.10.2.1 Special Constraint Resources.

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

III.1.10.10.3 [Reserved.]

III.1.11 Dispatch.

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

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, Baseline Deviation Offer or

Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

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

III.1.11.3 Dispatchable Resources.

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

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

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

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation

in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

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

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

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

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) All wind and hydro Intermittent Power Resources are required to be DNE Dispatchable Generators, with the exception of wind and hydro Intermittent Power Resources with an injection

capability of less than 5 MW that are connected through transmission facilities rated at less than 115 kV. A Distributed Energy Resource Aggregation is required to be a DNE Dispatchable Generator if it 1) consists entirely of wind or hydro Intermittent Power Resources or a combination of wind and hydro Intermittent Power Resources, and 2) participates as a Generator Asset.

(i) A Market Participant may elect to have a wind or hydro Intermittent Power Resource with an injection capability less than 5 MW that is connected through transmission facilities rated at less than 115 kV be a DNE Dispatchable Generator.

(ii) A Market Participant may elect to have a hydro Intermittent Power Resource or a Distributed Energy Resource Aggregation consisting entirely of hydro Intermittent Power Resources and participating as a Generator Asset be a DDP Dispatchable Resource if it is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range.

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

III.1.11.4 Emergency Condition.

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

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

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

Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

- (c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

- (i) at least once every 30 seconds: wind speed, and wind direction;
- (ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;
- (iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and
- (iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

- (i) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, irradiance, wind speed, and wind direction;

- (ii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit;
and
- (iii) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

- (a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.
- (b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

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

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

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

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

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which

shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, Interruption Cost, or Deviation Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time, Minimum Reduction Time or Minimum Deviation Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time, Minimum Reduction Time or Minimum Deviation Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed \$2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

(f) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has not satisfied its Minimum Deviation Time, its energy offer shall be increased by the Deviation Cost divided by the product of the Maximum Deviation and the Minimum Deviation Time.

(g) If the Rapid Response Pricing Asset is a Fast Start Demand Response Distributed Energy Resource Aggregation that has satisfied its Minimum Deviation Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the effect on transmission losses caused by

the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

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

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

III.2.6 Calculation of Nodal Day-Ahead Prices.

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

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional

increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset's Economic Maximum Limit, demand reduction at the Demand Response Resource's Maximum Reduction, and baseline deviation at the Demand Response Distributed Energy Resource Aggregation's Maximum Deviation, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;
- (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, Baseline Deviation Offers, or Increment Offer price cleared).

Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, dispatched Demand Response Distributed Energy Resource Aggregations, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

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

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

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

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

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

- (a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.
- (b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.
- (c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.
- (d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.
- (e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.
- (f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.
- (g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

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

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

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to

avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

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

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources, Demand Response Distributed Energy Resource Aggregations and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	Reserve Constraint Penalty Factor
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	\$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	\$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	\$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	\$50/MWh

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

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

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

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website.

The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

- (i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;
 - (ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;
 - (iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;
 - (iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and
 - (v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.
- (b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

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

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

using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

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

III.2.9B Final Day-Ahead Energy Market Results

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

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

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

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

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

III.3 Accounting And Billing

III.3.1 Introduction.

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

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 or Baseline Deviation 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, Settlement Only Distributed Energy Resource Aggregations, Demand Response Distributed Energy Resource Aggregations, 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.

(vi) **Real-Time Demand Reduction Obligation for Demand Response Distributed Energy Resource Aggregations** – 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 a Demand Response Distributed Energy Resource Aggregation at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction provided by a Demand Response Distributed Energy Resource Aggregation are equal to the sum of the demand reductions produced by its Distributed Energy Resources, which is each Distributed Energy Resource's performance as calculated pursuant to Section III.6.5(d), except such performance will not include any incremental energy injections for each Distributed Energy Resource. Demand reductions are increased by average avoided peak distribution losses.

(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 and Demand Response Distributed Energy Resource Aggregations**

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(b) and (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 and Demand Response Distributed Energy Resource Aggregations** – 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 and Demand Response Distributed Energy Resource Aggregations). 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.

(q) **Real-Time Energy Market Charge/Credit For Demand Response Distributed Energy Resource Aggregations** – 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 Distributed Energy Resource Aggregations. The charge or credit shall be equal to the sum of (1) 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; and (2) 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.

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 and Demand Response Distributed Energy Resource Aggregations), 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 a Demand Response Distributed Energy Resource Aggregation, the Metered Quantity For Settlement equals the sum of the demand reductions of each Distributed Energy Resource produced in response to a non-zero Dispatch Instruction, with the demand reduction for each Distributed Energy Resource calculated pursuant to Section III.6.5(d) except such performance will not include any incremental energy injections, and the hourly revenue quality meter data value apportioned over the five minute intervals in the hour in accordance with sub-section (f) below. If the Demand Response Distributed Energy Resource Aggregation provides five minute interval data, such data will be used in the Metered Quantity for Settlement calculation.
- (f) 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 and Distributed Energy Resources Associated with a Demand Response Distributed Energy Resource Aggregation

- (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 and for each Distributed Energy Resource associated with a Demand Response Distributed Energy Resource Aggregation. Individual Distributed Energy Resources with a Maximum Deviation Capability less than 10 kW and constituting a homogeneous population, as determined by the ISO, must aggregate their demand reduction and energy injection capability to achieve a Maximum Deviation Capability of at least 10 kW to report telemetry. The telemetry values shall measure: the real-time demand of Demand Response Assets as measured at their Retail Delivery Points; or the real-time demand and output of Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation as measured at their Retail Delivery Points and/or points of interconnection, and shall be reported to the ISO as an average value every five minutes. For a Demand Response Resource and a Demand Response Distributed Energy Resource Aggregation to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute, which 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 or a Distributed Energy Resource, 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 or a Distributed Energy Resources 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 or Distributed Energy Resource shall be excluded from the Demand Response Resource or Demand Response Distributed Energy Resource Aggregation 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 or a Distributed Energy Resource. 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 or a Distributed Energy Resource 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, Demand Response Resources, and Demand Response Distributed Energy Resource Aggregations 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, Demand Response Resources, and Demand Response Distributed Energy Resource Aggregations 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, 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.6 Distributed Energy Resource Aggregations

A Distributed Energy Resource Aggregation may participate in the New England Markets as described below. A Distributed Energy Resource Aggregation must comply with all applicable registration, metering, and accounting rules in this section.

III.6.1 Participation Requirements

An aggregation of Distributed Energy Resources that satisfies the requirements of Section III.6 may participate in the New England Markets as a Distributed Energy Resource Aggregation. A Distributed Energy Resource Aggregation shall:

- (a) comprise one or multiple facilities at one or more points of interconnection or Retail Delivery Points;
- (b) have regulation capability, energy injection capability, or combined demand reduction capability and energy injection capability of at least 0.1 MW;
- (c) be metered in accordance with Section III.6.4;
- (d) be registered pursuant to Section III.6.7;
- (e) participate in the wholesale markets as, and subject to all requirements applicable to a Generator Asset, Alternative Technology Regulation Resource, Continuous Storage Facility, Binary Storage Facility, Demand Response Resource, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation;
 - i. A Distributed Energy Resource Aggregation may participate as a Continuous Storage Facility or Binary Storage Facility to the extent the Distributed Energy Resource Aggregation as a whole is able to comply with all the requirements of a Continuous Storage Facility or Binary Storage Facility as stated in Sections III.1.10.6(b) and (c) respectively, regardless of whether any or all of the individual Distributed Energy Resources comprising the Distributed Energy Resource Aggregation meet the definition of Energy Storage Facility as defined in Section III.1.10.6.
- (f) not be located in the metering domain of a Host Utility that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such Host Utility to host Distributed Energy Resource Aggregations; and
- (g) meet the locational rules specified Section III.6.2.

III.6.2 Locational Requirements

A Distributed Energy Resource Aggregation must meet the following locational requirements.

- (a) For a Distributed Energy Resource Aggregation participating as an Alternative Technology Regulation Resource or a Demand Response Resource, all associated Distributed Energy Resources shall be located in a single DRR Aggregation Zone.
- (b) For a Distributed Energy Resource Aggregation participating as a Generator Asset, Binary Storage Facility, Continuous Storage Facility, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation, all associated Distributed Energy Resources shall be located within both a single DRR Aggregation Zone and a single Host Utility metering domain.
- (c) A Distributed Energy Resource Aggregation shall be settled at the DRR Aggregation Zone Node price, except where a single Distributed Energy Resource or a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, in which case, they are prohibited from aggregating with facilities at other Nodes, and will be settled at the single transmission Node price, not at the DRR Aggregation Zone Node price.
- (d) The ISO shall determine that all of the Distributed Energy Resources in a Distributed Energy Resource Aggregation are located in the same DRR Aggregation Zone. For Distributed Energy Resources in a Distributed Energy Resource Aggregation with energy injection capability or demand reduction capability of 1 MW or greater, the ISO's determination shall be based on the Host Utility's evaluation of the transmission node that will serve the Distributed Energy Resource.

III.6.3 Distributed Energy Resource Size Requirements

Individual Distributed Energy Resources participating in a Distributed Energy Resource Aggregation must meet the following size requirements.

- (a) A Distributed Energy Resource with overall injection capability of 5 MW or greater that participates in the New England Markets through a Distributed Energy Resource Aggregation must participate as a single facility Distributed Energy Resource Aggregation and be modeled and priced at a single transmission Node.
- (b) If a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at other Nodes. This group of Distributed Energy Resources may participate as a Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.
- (c) For a Distributed Energy Resource Aggregation with multiple Distributed Energy Resources participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, each

participating Distributed Energy Resource in the aggregation must have injection capability of less than 5 MW.

- (d) For a Distributed Energy Resource Aggregation participating as a Demand Response Resource, the size requirements in Section III.8 shall apply.
- (e) For a Distributed Energy Resource Aggregation participating as a Demand Response Distributed Energy Resource Aggregation, the size requirements in III.6.5(b) shall apply.
- (f) For a Distributed Energy Resource Aggregation participating as a Settlement Only Distributed Energy Resource Aggregation, the size requirements in III.6.6 shall apply.
- (g) For a Distributed Energy Resource Aggregation participating as an ATRR, the size requirements in Section III.14 shall apply.

III.6.4 Metering and Telemetry Requirements

Distributed Energy Resource Aggregations must meet the following metering and telemetry requirements.

- (a) Distributed Energy Resource Aggregations participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, must comply with the metering and telemetry requirements in Sections III.3.2.1 and III.3.2.2.
- (b) Distributed Energy Resource Aggregations participating as an Alternative Technology Regulation Resource must comply with the metering and telemetry requirements in Section III.14.2.
- (c) Distributed Energy Resource Aggregations participating as Demand Response Resources or Demand Response Distributed Energy Resource Aggregations must comply with the metering and telemetry requirements in Section III.3.2.2. The metering and communication equipment associated with each participating Distributed Energy Resource must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetering.
- (d) Metering for each Distributed Energy Resource participating in a Distributed Energy Resource Aggregation shall meet all applicable state and Host Utility requirements and be located at, a Retail Delivery Point, or point of interconnection as applicable. A Distributed Energy Resource's point of interconnection may be located behind a Retail Delivery Point to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration.
- (e) If a Distributed Energy Resource's point of interconnection is located behind a Retail Delivery Point it shall be reported such that its output or load does not impact the load reported for the Retail Delivery Point. A Distributed Energy Resource Aggregator may only propose a metering location behind a Retail Delivery Point if the Host Utility confirms in writing to the Distributed Energy Resource Aggregator that the appropriate metering and associated system upgrades are in place to support load and generation reporting and any necessary reconstitution. Proof of such

written confirmation from the Host Utility should be provided as part of the attestation as referenced in Section III.6.7(c)(i)2.

- (f) The Distributed Energy Resource Aggregator shall retain metering data for each participating Distributed Energy Resource for a period of six years for purposes of auditing.

III.6.5 Additional Requirements For Demand Response Distributed Energy Resource Aggregations

In addition to the rules applicable to all Distributed Energy Resource Aggregations, the following rules apply to Demand Response Distributed Energy Resource Aggregations. A Demand Response Distributed Energy Resource Aggregation allows Distributed Energy Resources with demand reduction capability, Distributed Energy Resources with energy injection capability and Distributed Energy Resources with energy withdrawal capability to participate in the wholesale markets as a single resource.

- (a) A Demand Response Distributed Energy Resource Aggregation must include Distributed Energy Resources with both demand reduction capability and energy injection capability and may include Distributed Energy Resources with energy withdrawal capability.
- (b) Size Requirements. Individual Distributed Energy Resources participating in a Demand Response Distributed Energy Resource Aggregation must meet the following size requirements:
 - (i) An individual Distributed Energy Resource with a Maximum Deviation Capability or ability to inject greater than or equal to 5 MW may not be registered as a component of a Demand Response Distributed Energy Resource Aggregation if its maximum energy injection capability is greater than its Maximum Facility Load. Such a Distributed Energy Resource must be the only facility associated with a Demand Response Distributed Energy Resource Aggregation and shall be modeled and priced at the transmission Node.
 - (ii) An individual Distributed Energy Resource with a Maximum Deviation Capability and maximum energy injection capability less than 5 MW may participate in a Demand Response Distributed Energy Resource Aggregation with other facilities located within the same DRR Aggregation Zone and metering domain. Such a Demand Response Distributed Energy Resource Aggregation shall be modeled and priced at the DRR Aggregation Zone Node.
 - (iii) If a group of Distributed Energy Resources has a Maximum Deviation Capability of, or can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at another Node. This group of Distributed Energy Resources may participate as a Demand Response

Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

- (c) **Baseline, Offer Requirements and Related Threshold Requirements.** For each Demand Response Distributed Energy Resource Aggregation:
- (i) The ISO shall establish a baseline for each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.2.
 - (ii) The Distributed Energy Resource Aggregator shall submit a Baseline Deviation Offer pursuant to Section III.1.10.1A(l) that reflects the aggregation's ability to deviate from its normal operational level.
 - (iii) Its Baseline Deviation Offer shall be subject to the Demand Reduction Threshold calculated pursuant to Section III.1.10.1A(f)
 - (iv) It may inject energy outside of dispatch intervals, which will be settled consistent with the rules for Settlement Only Resources.
 - (v) It may withdraw energy outside of dispatch intervals, which will be settled consistent with the rules for Load Assets.
- (d) **Performance Calculation.** The ISO shall calculate a Demand Response Distributed Energy Resource Aggregation's performance when it is dispatched. Such performance shall be the sum of the performance of each constituent Distributed Energy Resource. The ISO shall calculate the performance of each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.4.

III.6.6 Additional Requirements For Settlement Only Distributed Energy Resource Aggregations

A Settlement Only Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that may include Distributed Energy Resources with non-dispatchable energy injection capability and/or non-dispatchable energy withdrawal capability. A Settlement Only Distributed Energy Resource Aggregation shall comply with all Market Rules applicable to Settlement Only Resources and the following additional rules.

- (a) A Settlement Only Distributed Energy Resource Aggregation may submit a Supply Offer and/or Demand Bid in the Day-Ahead Energy Market in accordance with the requirements in Section III.1.10.1A(m).
- (b) There is no maximum size limit for a Settlement Only Distributed Energy Resource Aggregation, provided each constituent Distributed Energy Resource would otherwise be eligible to register as a Settlement Only Resource pursuant to OP-14.

III.6.7 Coordination of Registration and Modification

The process of coordinating the registration and activation for participation in the New England Markets between the ISO, the Distributed Energy Resource Aggregator and the Host Utility, regardless of the participation model chosen, includes four stages: 1) Initial Notification of Intent to Register a Distributed Energy Resource Aggregation; 2) Eligibility Confirmation; 3) Registration and Activation; and 4) Updates to an Existing Distributed Energy Resource Aggregation Registration. Completion of the Distributed Energy Resource Aggregation registration process requires that the Distributed Energy Resource Aggregator, Host Utility (or its agent) and ISO meet the following requirements for each stage.

- (a) Initial Notification
 - (i) Distributed Energy Resource Aggregator shall make an initial notification to both the ISO and the Host Utility (or the Host Utility's Agent) of its intent to register a Distributed Energy Resource Aggregation. Such notification shall include the information required by applicable ISO New England Manuals, including, but not limited to: the retail billing account(s) of the individual Distributed Energy Resource(s) participating in the aggregation, information regarding the location, anticipated size, technologies to be included, markets in which participation is planned, information required by the Host Utility Tariff and Terms and Conditions, and the participation model that the Distributed Energy Resource Aggregation intends to use for the Distributed Energy Resource Aggregation; interconnection agreement(s) for each participating Distributed Energy Resource, if required under state law; and an anticipated date to begin energy and/or ancillary service market participation.
- (b) Eligibility Confirmation. The Host Utility (or its agent) shall review each Distributed Energy Resource's eligibility to participate in a Distributed Energy Resource Aggregation and confirm the Aggregator's eligibility to register the proposed Distributed Energy Resource Aggregation in the manner established in this subsection. The time period for such review shall begin when the Host Utility or its agent receives the initial notification from the Distributed Energy Resource Aggregator and shall not exceed 60 calendar days. The Host Utility (or its agent) shall provide written notice to the ISO and the Distributed Energy Resource Aggregator of the eligibility confirmation, in accordance with the eligibility criteria described in this subsection. The eligibility confirmation shall be provided by the Host Utility or its agent to the appropriate relevant electric retail regulatory authority upon request. If the ISO does not receive timely notification from the Host Utility or its agent, then the ISO will assume that the operation of the

Distributed Energy Resource will not have a material reliability and/or safety impact on the applicable distribution system and shall be eligible to register with the proposed Distributed Energy Resource Aggregation.

(c)

- (i) In order to verify eligibility, the Host Utility or its agent shall, to the extent practicable based on the representations made by the Distributed Energy Resource Aggregator in the initial notification or through information otherwise in the Host Utility's (or its agent's) possession:
 1. confirm that each Distributed Energy Resource's metered net consumption or injection of energy will not be included in another Load Asset (if the Distributed Energy Resource Aggregation includes load) or Generator Asset.
 2. confirm, based on the representations made by the Distributed Energy Resource Aggregator that no individual Distributed Energy Resource (as identified by any retail billing account record of the Host Utility) is participating in a retail program that prohibits it from providing the requested service in New England Markets.
 3. confirm based on the representations made by the Distributed Energy Resource Aggregator that the proposed operation of each Distributed Energy Resource as part of the proposed Distributed Energy Resource Aggregation has appropriate interconnection and/or operating agreements in place with the Host Utility applicable to its technology and size.
 4. determine whether the Distributed Energy Resource Aggregation may pose significant risks, or may require further study to evaluate the potential significance of the risks, to the safe and reliable operation of the distribution system based on analysis of relevant risk factors, such as overloads, voltage, stability, short circuit interrupting capability, flicker, equipment operation frequency coordination, and contingency analysis.
 5. consider whether the proposed operation of any Distributed Energy Resource participating in a proposed Distributed Energy Resource Aggregation, or the Distributed Energy Resource Aggregation as a whole, imposes a need for distribution system upgrades to avoid safety and reliability impacts and, if so, confirm that the Distributed Energy Resource Aggregator has self-certified that such upgrades have been completed or will be completed before the Distributed Energy Resource desired activation date.

6. confirm that all the Distributed Energy Resources are within the Host Utility's metering domain.
 7. confirm that the net injection and consumption capability of the Distributed Energy Resources participating in the Distributed Energy Resource Aggregation do not exceed the capabilities as authorized by any associated interconnection agreements.
- (ii) For a Distributed Energy Resource Aggregation connecting to a Host Utility that served less than or equal to 4 million MWh of load in the previous fiscal year, the Host Utility (or its agent) shall confirm that the Host Utility has opted to allow Distributed Energy Resource Aggregations to participate in wholesale markets.
 - (iii) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is eligible in full or in part, the Distributed Energy Resource Aggregator shall provide a finalized list to the ISO and the Host Utility (or its agent) of the Distributed Energy Resources that have been found to be eligible for participation in the Distributed Energy Resource Aggregation, the participation model that the Distributed Energy Resource Aggregation intends to use, and the New England Markets in which the Distributed Energy Resource Aggregation plans to participate.
 - (iv) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is not eligible in full or in part, the Host Utility (or its agent) shall provide a written notice to the ISO and the Distributed Energy Resource Aggregator describing the eligibility criteria that were not met for any Distributed Energy Resource.
 - (v) In the event the Host Utility (or its agent) confirms that a Distributed Energy Resource Aggregation has not fulfilled the requirements of this subsection to be activated for participation in the New England Markets, and the Distributed Energy Resource Aggregator disputes this confirmation, the Distributed Energy Resource Aggregation may seek dispute resolution in a process established by the relevant electric retail regulatory authority, if available, or if not available, in accordance with Section I.6 of the Tariff. Any disputes regarding whether the Distributed Energy Resource Aggregator has appropriate contractual rights to offer a Distributed Energy Resource as part of a Distributed Energy Resource Aggregation in the New England Markets shall be resolved in the manner established in such contract, or otherwise by a court of competent jurisdiction as applicable.
 - (vi) In the event the ISO determines that a Distributed Energy Resource Aggregation is ineligible to participate in the New England Markets for reasons that are not related to the

Host Utility (or its agent's) review, the Distributed Energy Resource Aggregator may seek resolution in accordance with Section I.6 of the Tariff.

(d) Registration/Activation

- (i) In order to complete the registration and activation of a DERA the DER Aggregator shall:
 - 1. Provide both the ISO and the Host Utility (or its agent) with a desired activation date, once eligibility has been confirmed.
 - 2. Provide the information required by applicable ISO New England Manuals, as well as 1) an attestation, in a form prescribed by the ISO, stating that all participating Distributed Energy Resources are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements, and that the Distributed Energy Resource Aggregator retains the rights to offer the individual Distributed Energy Resource in New England Markets; and 2) confirmation in writing to the ISO and Host Utility (or its agent) that all Distributed Energy Resources in the Distributed Energy Resource Aggregation have been deemed eligible under subsection (b) of this section; and that the required metering and telemetry is in place, to meet the ISO requirements for participation in the planned markets.
- (ii) Prior to activation, the ISO must receive confirmation from the Host Utility (or its agent) that the Distributed Energy Resource Aggregator has met all applicable requirements with respect to metering and telemetry to enable the Host Utility or Assigned Meter Reader to include the Distributed Energy Resource Aggregation's metering in the appropriate Load Asset and metering domain.
- (iii) Distributed Energy Resources participating in a Distributed Energy Resource Aggregation may provide both retail and wholesale services to the extent such dual participation is allowed under state law or regulation, the Distributed Energy Resource Aggregator retains the rights to such services from the owner of the Distributed Energy Resource, and so long as the Distributed Energy Resource Aggregation is able to comply with all requirements under the ISO Tariff.

(e) Updates/Modifications to Existing Distributed Energy Resource Aggregation

- (i) When a Distributed Energy Resource is added to or removed from an existing Distributed Energy Resource Aggregation, the Distributed Energy Resource Aggregator shall update

the Distributed Energy Resource Aggregation's registration information. Such updates shall include: the information required by applicable ISO New England Manuals, sufficient to confirm that any newly added Distributed Energy Resources are eligible for participation; notification to the ISO and the Host Utility (or its agent) by the Distributed Energy Resource Aggregator of any Distributed Energy Resource being removed from the aggregation; verification that any required metering is in place for the reconfigured Distributed Energy Resource Aggregation; and an updated list of participating Distributed Energy Resources and the updated performance capabilities of the aggregation to be reflected in the aggregation's registration information.

- (ii) The Host Utility (or its agent) shall have up to 60 days to confirm eligibility and review any impacts associated with Distributed Energy Resources that the Distributed Energy Resource Aggregator is proposing to add to or remove from an existing Distributed Energy Resource Aggregation.
- (iii) Changes to the Distributed Energy Resources participating in a Distributed Energy Resource Aggregation shall become effective in the manner stated in Manual M-RPA.

III.6.8 Operational Coordination

The responsibilities related to the coordination of operations of a Distributed Energy Resource Aggregation between the Distributed Energy Resource Aggregator, the ISO, and the Host Utility are as follows:

- (a) The Distributed Energy Resource Aggregator shall: operate Distributed Energy Resources in a manner consistent with the limitations and operating orders established by the Host Utility; confer with the applicable Host Utility on a periodic basis to ensure available distribution service exists to operate its Distributed Energy Resources consistent with its New England Market obligations; submit outage requests for each Distributed Energy Resource Aggregation as necessary and to the extent required by ISO Operating Documents, in order to reflect known distribution system constraints or limitations that reduce the overall capability of the Distributed Energy Resource Aggregation; as required, account for any known limitations of the distribution system to which the Distributed Energy Resources are connected in its Offer Data for the Distributed Energy Resource Aggregation including restrictions that have been placed directly on the Distributed Energy Resource Aggregation by the Host Utility in the form of an override of an ISO Dispatch

Instruction; determine a Distributed Energy Resource-level operating plan to be provided to the Host Utility for analysis, subject to the requirements of each Host Utility.

- (b) The Distributed Energy Resource Aggregator shall have a Designated Entity or Demand Designated Entity, as applicable, for each of its Distributed Energy Resource Aggregations in accordance with the provisions set forth in ISO Operating Procedures. Designated Entities and Demand Designated Entities for Distributed Energy Resource Aggregations shall comply with the requirements of each Host Utility and/or relevant electric retail regulatory authority as applicable.
- (c) In the event that the Host Utility identifies conditions on the distribution system that result in actual or anticipated limitations on the operation of individual Distributed Energy Resources or Distributed Energy Resource Aggregations, the Host Utility shall notify the relevant Distributed Energy Resource Aggregator as soon as practicable.
- (d) The Host Utility may temporarily override the ISO's dispatch of a Distributed Energy Resource Aggregation. Such override shall only occur in circumstances where needed to maintain the reliable and safe operation of the distribution system.
- (e) Failure of a Distributed Energy Resource Aggregation to follow an ISO Dispatch Instruction due to a Host Utility override does not excuse the Distributed Energy Resource Aggregator from any applicable charges (including any penalties) to which the Distributed Energy Resource Aggregator is subject under the terms of the Tariff.
- (f) The ISO shall coordinate with the applicable Host Utility to avoid conflicting operational directives, which may include but is not limited to sharing Day-Ahead Energy Market results and Real-Time Dispatch Instructions.

III.9 Forward Reserve Market

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

III.9.1 Forward Reserve Market Timing.

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

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

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

III.9.2 Forward Reserve Requirements.

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

III.9.2.1 System Forward Reserve Requirements.

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

- (i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.
- (ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate

that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

- (iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.
- (iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

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

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

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

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response

Resource or Demand Response Distributed Energy Resource Aggregations the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource or Demand Response Distributed Energy Resource Aggregations as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

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

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

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource or Demand Response Distributed Energy Resource Aggregations.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregations the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, or Demand Response Distributed Energy Resource Aggregations the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

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

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

III.9.3 Forward Reserve Auction Offers.

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

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

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

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

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

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

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

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

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

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

will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

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

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

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, and Demand Response Distributed Energy Resource Aggregations in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

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

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation which has not been dispatched, it must be a Fast Start Demand Response Resource or a Fast Start Demand Response Distributed Energy Resource Aggregation and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

- (iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource or Demand Response Distributed Energy Resource Aggregation, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;
 - (iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;
 - (v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;
 - (vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;
 - (vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;
 - (viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.
- (b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:
 - (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;
 - (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.
2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
 - (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;
 - (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.
3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.
4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.
5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:
 - a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;
 - b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

- c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or
 - d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.
 - e) For Demand Response Distributed Energy Resource Aggregations, the ratio of (i) the sum of the applicable Deviation Cost and the baseline deviation cost to Minimum Deviation used in the Real-Time dispatch of the Demand Response Distributed Energy Resource Aggregation in the Operating Day to (ii) the maximum total hourly Deviation Cost and baseline deviation cost to Minimum Deviation submitted for the Demand Response Distributed Energy Resource Aggregation for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.
6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:
- a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.

- b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.
- c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were associated with a “Real-Time Demand Response Resource” or a “Real-Time Emergency Generation Resource” (as those terms were defined prior to June 1, 2018) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market

Participant. The ISO will normally perform the audit, at any time during the Forward Reserve Delivery Period, within five Business Days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five Business Day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10} \left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n \right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

- (i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.
- (ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.
- (iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.
- (iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.
- (v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the

increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources or Demand Response Distributed Energy Resource Aggregations for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers or Baseline Deviation Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

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

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

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

- (a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.
- (b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.
- (c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on

meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) **Generator Assets and Dispatchable Asset Related Demands** – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

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

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

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

where:

StartUp = cold Start-Up Fee.
NoLoad = No-Load Fee.
EnergyOffer_i = the Energy offer price for
Energy offer block *i*.
EcoMax = Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the

applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) Demand Response Resources and Demand Response Distributed Energy Resource

Aggregations – Qualifying megawatts for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have not been dispatched and Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation that has not been dispatched: is the amount of capability equal to or below the Maximum Deviation for the Demand Response Distributed Energy Resource Aggregation offered at or above the Forward Reserve Threshold Price. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Distributed Energy Resource Aggregations that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Baseline Deviation Offer price and a pro-rated amount of the Deviation Cost as defined below.

A Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation that has not been dispatched must offer its capability so that the following holds:

—

where:

- Interruption Cost* = Interruption Cost.
- Deviation Cost* = Deviation Cost
- EnergyOffer_i* = Demand Reduction Offer price or Baseline Deviation for Energy offer block *i*.
- MaxRed* = Maximum Reduction x 1 hour.
- MaxDev* = Maximum Deviation x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

Qualifying megawatts for a Demand Response Distributed Energy Resource Aggregation which has been dispatched: is the capability that is less than or equal to the Maximum Deviation and greater than the Minimum Deviation that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Distributed Energy Resource Aggregation. The Demand Response Distributed Energy Resource Aggregation must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Distributed Energy Resource Aggregation which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

- (a) Forward Reserve Delivered Megawatts for an off-line Generator Asset are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:
 - (i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

- (b) Forward Reserve Delivered Megawatts for an on-line Generator Asset are calculated in megawatts for each hour for each Reserve Zone as the minimum of:
 - (i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

- (c) Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:
 - (i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,
 - (ii) Forward Reserve Assigned Megawatts, or

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

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

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

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

- (f) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

- (i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer or in the Demand Response Distributed Energy Resource Aggregation's Baseline Deviation Offer,

- (ii) Forward Reserve Assigned Megawatts, or

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

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

- (i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate of that Resource, as applicable,
- (ii) Forward Reserve Assigned Megawatts, or
- (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

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

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

- (i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.
- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.
- (iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

(i) In determining Forward Reserve Delivered Megawatts for a Demand Response Distributed Energy Resource Aggregation the portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be increased by average avoided peak distribution losses, limited as described below.

- (i) The ISO will assume that Demand Response Distributed Energy Resource Aggregations first reduce their net load from the electricity system before providing additional energy injection.

- (ii) The portion of the Forward Reserve Delivered Megawatts not associated with energy injection shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Distributed Energy Resource Aggregation can reduce from the electric system based on the net load of its constituent Distributed Energy Resources.
- (iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with energy injection will be capped at the remaining energy injection capability of the Demand Response Distributed Energy Resource Aggregation.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

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

- (a) Forward Reserve Failure-to-Reserve Megawatts:
 - (i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:
 - (1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and
 - (2) Zero.
 - (ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

- (1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and
- (2) Zero.

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

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

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;

- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts:**

- (i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:
 - (1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;
 - (2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit, Minimum Reduction or Minimum Deviation, whichever is greater, (ii) the Resource's CLAIM10, and (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources and Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 10 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction or baseline deviation at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial demand reduction or baseline deviation at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

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

Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

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

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit, Minimum Reduction or Minimum Deviation, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources or Demand Response Distributed Energy Resource Aggregations that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources or Demand Response Distributed Energy Resource Aggregations, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate or Demand Response Distributed Energy Resource Aggregation Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction or Maximum Deviation minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

- (iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

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

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

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

Where:

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

III.9.7.3 Known Performance Limitations.

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

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

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

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

III.9.8 Forward Reserve Credits.

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

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

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

(b) $FRACP_{Zone}$ is defined as the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR = Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to:

applicable monthly $FRACP_{Zone}$ for TMNSR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

applicable monthly $FRACP_{Zone}$ for TMOR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.

The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

- (i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or
- (ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

- (i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

- (ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

- (i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

- (i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a zonal Forward Reserve requirement greater than zero, and
- (ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Settlement for Real-Time Reserves

For purposes of this Section III.10, unless otherwise expressly stated, the settlement interval is five minutes. 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.10.1 Reserve Quantity For Settlement

Each Resource receiving a Real-Time Reserve Designation pursuant to Section III.1.7.19 shall receive, for each settlement interval, a Reserve Quantity For Settlement. The Reserve Quantity For Settlement shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve. The Reserve Quantity For Settlement values will equal the corresponding Real-Time Reserve Designation values, adjusted downward after the fact to account for actual reserve capability based on Metered Quantity For Settlement.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time. Demand Response Resource credits will be limited as described in Section III.9.6.5(h).

(a) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMSR for an hour shall be equal to the sum of the Real-Time Reserve Credit for TMSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMSR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMSR for the interval. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMSR in that Load Zone.

(b) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMNSR shall be equal to the sum of the Real-Time Reserve Credit for TMNSR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMNSR for an interval is calculated by multiplying the Market

Participant's Resource specific Reserve Quantity For Settlement for TMNSR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMNSR for the interval. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific hourly Real-Time Reserve Credits for TMNSR in that Load Zone.

(c) A Market Participant's Resource specific hourly Real-Time Reserve Credit for TMOR shall be equal to the sum of the Real-Time Reserve Credit for TMOR for the settlement intervals in that hour. The Real-Time Reserve Credit for TMOR for an interval is calculated by multiplying the Market Participant's Resource specific Reserve Quantity For Settlement for TMOR (where any portion of Reserve Quantity For Settlement provided by either a Demand Response Resource, other than MWs associated with Net Supply, or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with energy injection, is increased by average avoided peak distribution losses) for the interval by the Real-Time Reserve Clearing Price for TMOR for the interval. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

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

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT_CHRG_RT}_i]$$

Where:

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

Reserve Charge Allocation MW = Market Participant *k*'s Real Time Load Obligation in Load Zone *i* adjusted for the Reserve Quantity For Settlement MWs of Market Participant *k*'s Dispatchable Asset Related Demand MWs in Load Zone *i*.

$RT_CHRG_RT_i = [IRT_SUP_PMNT]/RT_P_WTD_LD_OB] \times [RT_P_RATIO]$ for TMSR, TMNSR, or TMOR, as applicable.

$RT_P_WTD_LD_OB = \sum [Reserve\ Charge\ Allocation\ MW_{si}] \times [P_RATIO_i]$ for TMSR, TMNSR or TMOR, as applicable;

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

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

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

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each settlement interval such that a Market Participant will not receive compensation for Real-Time Operating Reserve MWs provided to satisfy a Forward Reserve Obligation.

For purposes of the calculations in this Section III.10.4: (1) when a Market Participant assigns a Forward Reserve Resource in one Reserve Zone to meet a Forward Reserve Obligation in another Reserve Zone, any Forward Reserve Obligation Charge megawatts associated with that Resource are allocated to the Reserve Zone in which the Market Participant holds the Forward Reserve Obligation; and (2) if a Market Participant satisfies a Forward Reserve Obligation for TMOR with Forward Reserve Delivered MW of TMNSR, the Forward Reserve Obligation Charge megawatts are allocated to the Market Participant's Forward Reserve Obligation for TMOR.

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

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Reserve Quantity For Settlement (where any portion of Reserve Quantity For Settlement provided by a Demand Response Resource or a Demand Response Distributed Energy Resource Aggregation, other than MWs associated with Net Supply, is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

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

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

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

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

New England Governors, State Utility Regulators and Related Agencies*

Connecticut

The Honorable Ned Lamont
Office of the Governor
State Capitol
210 Capitol Ave.
Hartford, CT 06106
bob.clark@ct.gov

Connecticut Attorney General's Office
165 Capitol Avenue
Hartford, CT 06106
John.wright@ct.gov
Lauren.bidra@ct.gov

Connecticut Department of Energy and
Environmental Protection
79 Elm Street
Hartford, CT 06106
Eric.annes@ct.gov
Robert.snook@ct.gov

Connecticut Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051-2605
steven.cadwallader@ct.gov
robert.luysterborghs@ct.gov
Seth.Hollander@ct.gov
Robert.Marconi@ct.gov

Maine

The Honorable Janet Mills
One State House Station
Office of the Governor
Augusta, ME 04333-0001
Jeremy.kennedy@maine.gov
Elise.baldacci@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
Maine.puc@maine.gov

Massachusetts

The Honorable Charles Baker
Office of the Governor
State House
Boston, MA 02133

Massachusetts Attorney General's Office

One Ashburton Place
Boston, MA 02108
rebecca.tepper@state.ma.us

Massachusetts Department of Energy
Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114
Robert.hoaglund@mass.gov
ben.dobbs@state.ma.us

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110
Nancy.Stevens@state.ma.us
morgane.treanton@state.ma.us
William.J.Anderson2@mass.gov
dpu.electricsupply@mass.gov

New Hampshire

The Honorable Chris Sununu
Office of the Governor
26 Capital Street
Concord NH 03301

New Hampshire Department of Energy
21 South Fruit Street, Ste 10
Concord, NH 03301
Jared.S.Chicoine@energy.nh.gov
Christopher.j.ellmsjr@energy.nh.gov
Thomas.C.Frantz@energy.nh.gov
Karen.P.Cramton@energy.nh.gov
Amanda.O.Noonan@energy.nh.gov
joshua.w.elliott@energy.nh.gov

New Hampshire Public Utilities Commission
21 South Fruit Street, Ste. 10
Concord, NH 03301-2429
david.j.shulock@energy.nh.gov
RegionalEnergy@puc.nh.gov

Rhode Island

The Honorable Daniel McKee
Office of the Governor
82 Smith Street
Providence, RI 02903
Rosemary.powers@governor.ri.gov

New England Governors, State Utility Regulators and Related Agencies*

Rhode Island Office of Energy Resources
One Capitol Hill
Providence, RI 02908
christopher.kearns@energy.ri.gov
nicholas.ucci@energy.ri.gov

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888
ronald.gerwatowski@puc.ri.gov
todd.bianco@puc.ri.gov

Vermont

The Honorable Phil Scott
Office of the Governor
109 State Street, Pavilion
Montpelier, VT 05609
jason.gibbs@vermont.gov

Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701
mary-jo.krolewski@vermont.gov
Margaret.cheney@vermont.gov

Vermont Department of Public Service
112 State Street, Drawer 20
Montpelier, VT 05620-2601
bill.jordan@vermont.gov
june.tierney@vermont.gov

New England Governors, Utility Regulatory and Related Agencies

Jay Lucey
Coalition of Northeastern Governors
400 North Capitol Street, NW, Suite 370
Washington, DC 20001
coneg@sso.org

Heather Hunt, Executive Director
New England States Committee on Electricity
424 Main Street
Osterville, MA 02655
HeatherHunt@nescoe.com
JasonMarshall@nescoe.com
JeffBentz@nescoe.com

Meredith Hatfield, Executive Director
New England Conference of Public Utilities
Commissioners
72 N. Main Street
Concord, NH 03301
mhatfield@necpuc.org

Matthew Nelson, President
New England Conference of Public Utilities
Commissioners
One South Station
Boston, MA 02110
matthew.nelson@mass.gov