May 13, 2011

VIA ELECTRONIC FILING

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

Re: ISO New England Inc., NEPOOL Participants Committee, and Participating Transmission Owners Administrative Committee; Filing of FTR Enhancements; Docket No. ER11-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. (the "ISO" or "ISO-NE") joined by the New England Power Pool ("NEPOOL") Participants Committee,[2] and the PTO Administrative Committee ("PTO AC") on behalf of the Participating Transmission Owners ("PTOs") (together, the "Filing Parties"), hereby jointly submit this transmittal letter and revised sections of the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO Tariff") to change several aspects of the Financial Transmission Right ("FTR") market design (the "FTR Enhancements").[3]

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

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

[3] Under New England's RTO arrangements, the rights to make this filing of changes to Market Rule 1 under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole market participant stakeholder process for advisory voting on ISO matters, supported the changes reflected in this filing and accordingly, joins in this Section 205 filing. The PTOs possess certain rights under Section 205 to modify certain terms, conditions and rates in Schedule 21 of the ISO Tariff in accordance with transmission operating agreements, prior Commission orders, and/or applicable case law. The PTO AC joins this filing in support of the changes to Schedule 21-Common that are included in this filing.

The FTR Enhancements include changes to Section I of the ISO Tariff,[4] as well as to the OATT (including Schedule 21-Common),[5] Market Rule 1, and Appendix C to Market Rule 1, and which: (1) revise several aspects of the annual and monthly FTR auctions process[6] and corresponding provisions of the Auction Revenue Rights ("ARRs") allocation process;[7] and (2) include new tariff sheets to allow earlier implementation of the already approved plan to convert Qualified Upgrade Awards ("QUAs") to Incremental Auction Revenue Rights ("IARRs").[8] In support of the FTR Enhancements, this filing includes the testimony of Jonathan B. Lowell, Principal Analyst, Market Development, which is sponsored solely by the ISO (the "Lowell Testimony").

As explained in Section V of this transmittal letter, the Filing Parties respectfully request that the Commission accept the tariff changes associated with the conversion of QUAs to IARRs to be effective as of July 13, 2011. The Filing Parties request that the tariff changes involving the FTR auction process become effective on or after January 1, 2012, with two weeks' written notice of the actual effective date to be provided to the Commission. The proposed tariff sheets are marked to reflect the different requested effective dates for the two elements of the FTR Enhancements.

I. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS

A. The ISO

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

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[4] The Section I changes involve modifications to the definitions in Section I.2.2 (to add definitions of "Incremental ARR" and "Incremental ARR Holder" and make conforming changes).

[5] The OATT changes (including those in Schedule 21-Common) substitute "Incremental ARR" terminology for "Qualified Upgrade Award" terminology.

[6] *See, e.g.*, revised ISO Tariff Sections III.7.1.1, III.7.1.2, III.7.3.6, III.7.3.7, III.7.3.10 and III.7.3.14.

[7] *See, e.g.*, revised ISO Tariff Sections III.C.1, III.C.2.2, III.C.3.2, III.C.6 and III.C.7.

[8] *See, e.g.*, revised Section III.C.8 and new Section III.C.8.1 of Appendix C to Market Rule 1. Note, also, that Section III.5.2.2(b) has been modified to remove language that should have been removed, but was overlooked, as part of the joint filing in Docket No. ER10-1190-000 to suspend the Secondary FTR Market. *See* delegated letter order issued in that docket, accepting those ISO Tariff changes, on June 11, 2010.

B. NEPOOL

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 440 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Process for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the [ISO] Tariff, [Transmission Operating Agreement] and the Market Participant Services Agreement included in the [ISO] Tariff."

C. The PTOs

The PTOs[9] are Transmission Service Providers that offer both Local Network Service ("LNS") and Local Point-to-Point Service to Transmission Customers over Non-PTF Transmission Facilities ("Local Service") on an open-access basis under Schedule 21 of the ISO OATT. Pursuant to the terms of the Transmission Operating Agreement ("TOA") among the PTOs 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 the Transmission Facilities of the PTOs, including those used to provide service under Schedule 21. As it pertains to the instant filing, Section 3.04 of the TOA, in relevant part, grants the PTOs authority under Section 205 of the Federal Power Act to submit filings to the Commission in matters affecting the rates, terms and conditions of Local Service under Schedule 21.

Schedule 21 of the ISO OATT is comprised of two distinct parts. First, under the common provisions of Schedule 21 ("Schedule 21–Common"), the PTOs have collectively accumulated the common terms and conditions of Local Service applicable to transmission

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[9] The PTOs include: Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; NSTAR Electric Company; Central Maine Power Company; Maine Electric Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; New Hampshire Transmission, LLC; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company d/b/a National Grid; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company on behalf of the NU Companies; Taunton Municipal Lighting Plant; Town of Norwood Municipal Light Department; Town of Reading Municipal Light Department; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc.; Vermont Electric Power Company, Inc.; Vermont Transco, LLC; and Vermont Public Power Supply Authority.

service over the local facilities of all of the PTOs. Second, each PTO has its own individual Schedule 21 schedule ("Local Service Schedule"), containing the rates, terms and conditions applicable to service over the Local Facilities owned by that particular PTO. The Schedule 21 Local Service Schedules primarily contain the rates that would apply for transmission service over the Local Facilities owned by the particular PTO, and may also include terms and conditions of service in addition to those contained in Schedule 21-Common.

Pursuant to Section 3.04 of the TOA, each PTO has the authority to submit filings under Section 205 of the FPA to establish and to revise the rates, terms and conditions of Transmission Service under its individual Local Service Schedule affecting the facilities owned by that particular PTO. In addition, the PTOs, acting jointly through the PTO AC, and in accordance with the TOA and Disbursement Agreement among the PTOs, have the authority to submit filings under Section 205 of the FPA to establish and revise the common provisions of Local Service under Schedule 21.[10] In this filing, the PTO AC is sponsoring the modifications to the common provisions of Schedule 21 on behalf of the PTOs. While ISO-NE, as the RTO for New England, has operational control over the Non-PTF Transmission Facilities, the PTOs, both individually and collectively, determine the rates, terms and conditions of transmission service over such facilities.

For purposes of this filing, the PTOs have coordinated through the PTO AC with ISO-NE and with the other transmission owners in New England to make this filing. While, pursuant to Section 3.04 (a) of the TOA, NEPOOL advisory approval was not required before making this filing with the Commission, it is important to note that, to date, NEPOOL stakeholders have not raised any indication that they disagree with the modifications to the common provisions of Schedule 21 proposed herein.

D. Communications

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

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[10] TOA Sections 2.05, 3.03, and 3.04; Rate Design and Funds Disbursement Agreement ("Disbursement Agreement") Sections 1.01, 1.02, and 2.01.

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II. STANDARD OF REVIEW

The instant revisions are submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[12] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[13] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[14] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable -- and [this inquiry does not] extend to determining whether a proposed rate

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

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

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

[14] *Id.*

schedule is more or less reasonable than alternative rate designs."[15] The revision "need not be the only reasonable methodology, or even the most accurate."[16] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[17]

III. DESCRIPTION OF, AND RATIONALE FOR, THE FTR ENHANCEMENTS

A. The Existing FTR Market Structure

The operational scheduling of the New England Transmission System is based on the economic clearing of supply and demand through participant-submitted Supply Offers and Demand Bids, as well as the known characteristics and constraints of the New England Transmission System.[18] Transmission Customers pay for, and receive, network transmission service ("Regional Network Service") that entitles them to the use of a share of the entire New England Transmission System, and neither generation nor load needs to actually schedule transmission service. The commitment of resources for the next Operating Day is initially conducted through the Day-Ahead Energy Market. The Day-Ahead Energy Market produces Locational Marginal Prices ("LMPs") at every injection and withdrawal node on the system. Generators are paid the LMP at their location and loads pay the LMP (generally at load zone weighted average) at their location. LMP differences between locations are indications of either congestion costs or marginal losses. The congestion cost components of LMPs are the result of the security-constrained economic dispatch of energy within the physical limits of the transmission system.

When the New England Transmission System is constrained and cannot move additional power across a constraint, higher-priced generation is dispatched up on the "import-constrained side" of the constraint to ensure that the energy balance is maintained.[19] In this situation, the LMP on the import-constrained side would be higher than the LMP on the "export-constrained side" because more expensive generation must be dispatched to meet load on the import-constrained side.

An FTR is a financial instrument that entitles the holder to receive compensation equal to Congestion Costs that arise between two locations when there are binding transmission constraints in the Day-Ahead Energy Market between those locations. FTRs can be used by Market Participants to hedge their exposure to LMP congestion cost volatility. Each FTR is

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

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

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

[18] *See* Lowell Testimony at 4.

[19] *See* Lowell Testimony at 4-5.

unidirectional and is defined in megawatts from a point-of-receipt (where the power is injected onto the New England Transmission System) to a point-of-delivery (where the power is withdrawn from the New England Transmission System).

The cash flow of an FTR is determined by the difference between the congestion component of the day-ahead LMP at the point-of-receipt and the point-of-delivery. Because the FTR is an obligation, the cash flow can be positive or negative. The ISO's existing market design requires participants to bid in an auction to acquire FTRs and the right to future day-ahead transmission congestion revenues ("TCRs"). By acquiring an FTR, a Market Participant offsets congestion cost exposure in the Day-Ahead Energy Market on a given path (source, sink, amount) with the payout (or charge) from the FTR, and in so doing hedges congestion costs on that path.[20]

In addition to FTRs, the current market design also features a complementary congestion management mechanism, Auction Revenue Rights ("ARRs").[21] As stated previously, Market Participants currently acquire FTRs by bidding into the FTR auctions. Winning bidders pay the appropriate clearing price for each of their successful bids. The auction revenues received from the successful bidders are distributed to Congestion Paying LSEs as ARRs, and entities funding transmission upgrades through QUAs. The amount of ARRs allocated to each participant depends upon the Load Zone in which the participant's real-time load is located, the participant's share of the real-time load at the time of the system peak, and the value of transmission paths from each generator in the control area to the respective Load Zone as determined by the FTR auction results. Congestion Paying LSEs may choose to use the revenues they receive from ARRs to help pay the costs of acquiring FTRs, or they may choose to keep the revenues they receive from ARRs.

B. The FTR Enhancements' Proposed Changes to the FTR Auction Structure, and Their Benefits

As described in the Lowell Testimony, the FTR Enhancements provide a two-round structure in the auction of annual FTRs and introduce monthly balancing (*i.e.*, reconfiguration) auctions to supplement the existing prompt-month auctions of monthly FTRs.[22]

In the existing annual auction, 50% of the network capacity during on-peak hours is made available in an auction for the on-peak period and 50% of the network capacity during off-peak hours is made available in a separate auction for the off-peak period. Each auction is conducted in a single round. Under the proposed enhancements, 25% of the network capacity would be made available in the first round of separate on-peak and off-peak annual auctions. The results

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[20] *See* Lowell Testimony at 6.

[21] *Id.*

[22] *See* Lowell Testimony at 7-8. See proposed changes to ISO Tariff Sections III.7.1.1, III.7.1.2, III.7.3.6, III.7.3.7, III.7.3.10 and III.7.3.14.

of these auctions would be published prior to the start of a second and final round. In the second round, an incremental 25% of the network would be made available for a cumulative total of 50% of the network available in the separate on-peak and off-peak annual auctions. FTRs acquired in the first round would be accounted for during the second round to ensure the 50% available network capacity is not oversold. Auction participants that acquired FTRs in the first round would be able to sell those FTRs in the second round if they so desire.

In the existing FTR market, on-peak and off-peak monthly FTRs are auctioned only once for each month in monthly auctions, when the month to be auctioned is the prompt month (*i.e.*, just prior to the start of the month to be auctioned). Currently, the full, available network capacity, accounting for FTRs sold in the annual auction, is made available for sale in the prompt month auctions. In the enhanced design, every remaining month in the calendar year would be auctioned every month. No additional network capacity beyond the 50% capacity offered for sale in the annual auctions would be available in the non-prompt month auctions. The non-prompt month auctions allow network capacity previously sold in the annual auctions to be reconfigured amongst auction participants based on their changing requirements and expectations for the market, as well as the purchase of any unsold portion of the 50% of network capacity made available in the annual auction. Auction participants would be able to expand, liquidate or otherwise modify their existing FTR portfolios both by trading via the auction with other FTR holders, and by acquiring previously available but unsold network capacity.

Under the enhanced FTR market design, the on-peak and off-peak prompt month auctions would remain essentially unchanged from the current design. The remaining network capacity would be made available. Planned transmission outages during the month and all previously sold FTRs effective during the month would be accounted for to ensure the network is not oversold.

As explained in the Lowell Testimony,[23] the FTR Enhancements present two principal benefits, which then make possible a number of secondary benefits. The principal benefits are: (1) greatly increased FTR liquidity and (2) enhanced price discovery. In the current design, an FTR purchased in the annual auction that the holder finds no longer useful after a period of several months, perhaps due to reduced load obligations, new power supply arrangements or because congestion patterns have changed, can only be liquidated one month at a time in the prompt month auctions. Similarly, a Load Serving Entity ("LSE") that takes on new long-term load obligations, say for 6-12 months, can only implement an FTR congestion risk hedging strategy a single month at a time. Under the enhanced design, FTR positions for the entire remainder of the year would be tradeable every month.

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[23] *See* Lowell Testimony at 9-12.

1. Increased Liquidity

There is some evidence that the enhanced FTR market design would lead to increased FTR transaction volume.[24] During NEPOOL stakeholder discussions that initiated the ISO's design effort, a Market Participant presented historical information illustrating significant increases in PJM FTR volumes traded between the periods before and after the implementation of the "Balance of Planning Period" ("BoPP") FTR auctions in 2006.[25] The New England FTR Enhancements bear important similarities to the BoPP design in PJM, particularly with regard to improved liquidity. Increased trading volumes in New England are certainly a potential positive outcome.

2. Enhanced Price Discovery

Enhanced price discovery is the second principal benefit.[26] Adding a second round to the annual auction, with significant new capacity made available in each round, and with clearing prices published at the end of each round, would give auction participants an important additional source of price information that is simply unavailable in the current design. The monthly reconfiguration auctions would, for the first time, allow participants and the ISO to estimate a forward monthly price curve that exposes the impacts of factors that change over the course of the year, such as seasonal congestion, mid-year generation additions, and transmission improvements. Together, increased liquidity and improved price discovery enhance the ability to manage the market and credit risks associated with the FTR market.

3. Efficient Resource Allocation

One of the ISO's important objectives for any ISO-administered market is the efficient allocation of resources.[27] The auction design on which the FTR market is based can help or hinder that objective. In a perfectly efficient market, all buyers and sellers would obtain a portfolio representing exactly the quantities of FTR paths desired at the final market clearing prices. No buyers would desire additional quantities at the final clearing prices, nor would they be interested in selling any part of their portfolio at the clearing price.

In a single-round auction, this outcome is difficult to achieve than in the multiple-round format established by the FTR Enhancements. Little or no market price information is available, and auction participants must rely on their own estimates of future congestion to infer a market

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[24] *See* Lowell Testimony at 9-10.

[25] *See* Presentation of Mr. Bruce Bleiweis at the July 2010 NEPOOL Markets Committee meeting, available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2010/jul12142010/a7_dc_energy_presentation_07_12_10.pdf.

[26] *See* Lowell Testimony at 10.

[27] *See* Lowell Testimony at 10-11.

value. Access to the limited information that is available may be asymmetric because smaller participants may not have the staff or analytical expertise available to extract useful market intelligence from the masked participant bid data and cleared FTR results published by the ISO. Conceptually, multi-round auction designs provide a means to address this concern. In the extreme, rounds can be allowed to continue indefinitely until a round is completed in which no bids or offers clear. At that point, an efficient allocation of network capacity has been achieved and the auction is terminated. Prices at the end of each round would eventually converge towards a market outcome representing an efficient FTR allocation.

Auctions for complementary goods with sub-additive valuations[28] subject bidders to the "Exposure Problem." For example, suppose a market participant can adequately hedge his congestion risk by acquiring a 10 MW FTR across the Connecticut Import Interface, and there are numerous FTR paths that source outside of Connecticut and sink inside the import interface. Any path provides the desired hedge, but if the participant bids for only a single path, and the offer does not clear, the participant would be unhedged. To avoid this risk, the auction participant can submit two separate bids, each for a different 10 MW path across the import interface, but this would expose the participant to the risk of having both bids clear for a total of 20 MW across the interface. If this happens, the auction participant would overpay for the cleared portfolio of FTRs. In a single-round auction, participants may be forced to manage this exposure by underbidding for one or both goods, leading to depressed prices. A multiple-round auction allows bidders to iteratively acquire their desired portfolios with reduced risk, without the additional complexity of "package bidding,"[29] an approach used in radio frequency spectrum auctions conducted by the Federal Communications Commission.

4. Summary

In summary, a two-round annual auction, with the publication of only limited results between the rounds, provide the great majority of the benefits of multi-round auctions suggested by theory, while limiting both the transaction costs imposed on participants and any possibilities for non-competitive behavior that might arise with a larger number of rounds.[30]

C. The FTR Enhancements' Proposed Changes to the ARR Methodology

The New England market design utilizes ARRs to distribute the proceeds from the sale of FTRs to Congestion Paying LSEs. The amount of ARRs allocated to each participant depends

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[28] For example, Good A is independently valued by the participant at X, and Good B is independently valued at Y. A sub-additive valuation is present where the value of holding both Goods A and B together is less than X plus Y. FTRs over different but related paths have characteristics of complementary goods.

[29] Package bidding allows participants to submit offers for combinations of goods, but can be impractical when a large number of complementary goods are included in the auction. With more than 900 FTR source and sink locations in New England, the combinatorial possibilities make package bidding in the FTR market impractical, if not infeasible. *See* Lowell Testimony at n.5.

[30] More detailed discussion of these topics is contained in the Lowell Testimony at 12-15.

upon the Load Zone in which the participant's real-time load is located, the participant's share of the real-time load at the time of the system peak, and the value of transmission paths from each generator in the region to the respective Load Zone as determined by the FTR auction results. As noted above, Congestion Paying LSEs may choose to use the revenues they receive from ARRs to help pay the costs of acquiring FTRs, or they may choose to keep the revenues they receive from ARRs.

In the FTR Enhancements, the ARR methodology is being revised in minor ways to recognize the additional annual auction rounds and the monthly reconfiguration auctions.[31] The auction revenues associated with each annual auction round would be allocated to Congestion Paying LSEs based on the specific auction prices resulting from each round. This is completely consistent with the current methodology.

The monthly reconfiguration auctions (other than the prompt month auctions) are a new element in the FTR market design and consequently, the current ARR methodology does not contemplate this element. The current ARR methodology utilizes a four-stage process. Within each stage, the methodology requires monthly auction prices and monthly peak loads,[32] and uses an iterative algorithm that typically requires significant administrative effort to ensure successful completion. Considering the large increase in the number of monthly FTR auctions, the ISO has determined that it is administratively infeasible to conduct the current ARR process for each and every monthly auction.[33]

Further, no new network capacity is made available in the reconfiguration auctions. The net auction revenues to be distributed by the ARR process would derive primarily from purchases of previously unsold capacity and counterflow bids.[34] Transactions that represent transfers of previously sold capacity from one participant to another would not produce any net auction revenue for allocation to Congestion Paying LSEs, because the revenue from those transactions accrues to the FTR seller. Conversely, the prompt month auctions make available the remaining unsold network capacity of the system, sales of which would lead to net auction revenues for allocation through the ARR process.

Considering the infeasibility of conducting the current ARR process for every monthly auction, and the likelihood that the majority of the net auction revenues associated with June, for example, would derive from the June prompt month auction, the new ARR design accumulates

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[31] *See* Lowell Testimony at 17-20. *See* proposed revisions to ISO Tariff Sections III.C.1, III.C.2.2, III.C.3.2, III.C.6 and III.C.7.

[32] More specifically, the ARR calculation requires each Congestion Paying LSE's Real-Time Load Obligation at the time of the monthly coincident peak demand for the New England Control Area. *See* Market Rule 1, Section III.C.7.

[33] For the month of January, there would be 24 separate monthly auctions: two prompt month auctions (on-peak and off-peak) and 22 reconfiguration auctions (February-December, on-peak and off-peak).

[34] A counterflow bid, in this context, is an offer to purchase a FTR on a path that may already be partly or fully subscribed, but in the opposite direction.

all of the net auction revenues from all of the June reconfiguration auctions plus the June prompt month auction. The accumulated June net auction revenue is then allocated to Congestion Paying LSEs using the prices from the June prompt month auction and the existing ARR methodology. The prompt month prices are the most current prices for the month when the ARR allocation is performed, and represent the market's expectation for congestion during the prompt month in the Day-Ahead Energy Market.

The approach reasonably balances the intent and operation of the existing monthly ARR methodology, which is to distribute FTR auction revenues back to those who pay congestion, against the practical realities of administering the FTR market.

D. The FTR Enhancements' Conversion of QUAs to IARRs

The FTR Enhancements present an opportunity to create the software infrastructure allowing QUAs to be permanently replaced by IARRs, as required by previous filings.[35] The existing QUA process is conducted at the end of each FTR auction to measure the change in the dollar value of awarded FTRs attributable to specific transmission upgrades funded by specifically identified entities. These include only Elective Transmission Upgrades and Generator Interconnection Related Upgrades, and not upgrades paid for through the Pool PTF and Pool RNS Transmission Rates.

The existing QUA process is time-consuming to administer and the determination of the actual monetary value of a specific QUA in any particular FTR auction is not particularly transparent for the QUA holders.[36] After an FTR auction is completed, the QUA process repeats the auction starting with a network topology that initially excludes all of the transmission upgrades, and then adds each upgrade back into the topology in a sequential manner. The increased value of the auction arising from the inclusion of each sequential upgrade becomes the value of the QUA award for the associated upgrade. As the number of QUAs increases, the number of the sequential auction reruns increases, and the complexity of the award determinations increases. Indeed, in the Commission's 2002 order accepting ISO-NE's "standard market design" proposal,[37] the Commission recognized that the QUA process was intended to be replaced by a permanent process.[38] Also, as anticipated in the SMD Order, the rules designed to implement Long-Term Transmission Rights (known to New England stakeholders as Long-term FTRs, or "LFTRs"), submitted by ISO New England and approved by

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[35] *See* revised Section III.C.8 and new Section III.C.8.1 of Appendix C to Market Rule 1.

[36] *See* Lowell Testimony at 20.

[37] *See New England Power Pool and ISO New England*, 100 FERC ¶ 61,287 (2002) ("SMD Order"). The SMD Order accepted in part and modified in part the proposal jointly filed by the ISO and NEPOOL on July 15, 2002 to replace the design of the then-existing NEPOOL markets with Market Rule 1, commonly referred to as "Standard Market Design", a. *See New England Power Pool and ISO New England*, NEPOOL Standard Market Design, Docket No. ER02-2330 (July 15, 2002).

[38] *See* SMD Order at P 15 ("The QUA process is a temporary measure which ISO-NE anticipates replacing . . ..").

the Commission in 2008,[39] created a new process to replace QUAs with IARR awards for entities funding transmission upgrades.

IARRs are not currently effective in New England. The rules have been approved, but have not been made effective pending the development of necessary software infrastructure that was planned as part of comprehensive software development and implementation effort to support LFTRs. Although preliminary LFTR development commenced in 2008, LFTR-related market and credit risk issues must be successfully resolved before development and implementation of the LTTR software infrastructure can be completed. However, the development work necessary to support the FTR Enhancements presents an opportunity to create the software infrastructure allowing QUAs to be permanently replaced by IARRs.

1. The Advantages of Implementing IARRs as Part of the FTR Enhancements

There are three advantages of implementing IARRs as part of the FTR Enhancements.[40] First, IARRs provide transparency to the award holder. The only additional information a participant requires to determine the value of an IARR is the nodal pricing from the appropriate FTR auction. This information is published at the conclusion of every auction. With the existing QUA process, it is simply not possible for a market participant to calculate the value of a QUA. The calculation requires rerunning the auction, which necessarily requires having all of the submitted bid information. Only the ISO has all the submitted bids, and therefore, only the ISO is able to determine the value of a QUA for each auction.

Second, in the time since the IARR rules were approved in 2008, several stakeholders have requested "early" implementation of IARRs. This is the first opportunity to meet that request, and is likely to be the only opportunity until LFTR development resumes.

Third, the IARR process does not require the 24 sequential iterations required for each FTR auction. This greatly simplifies the time required to administer the FTR market. With the additional annual auction rounds and monthly reconfiguration auctions, it would simply not be feasible to continue with the existing QUA process. For all practical purposes, replacing QUAs with IARRs is a step required to make it possible for the ISO to administer the additional auctions required by the FTR Enhancements.

2. The IARR Process

Under the FTR Enhancements, the ISO would evaluate transmission upgrades and would

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[39] In October 2008, the Commission granted final approval for market rules to implement long-term transmission rights in New England. *See New England Power Pool and ISO New England*, 125 FERC ¶ 61,069 (2008) ("LFTR Order"). Those rules, which encompassed the replacement of QUAs with IARRs, have not yet gone into effect, pending the resolution with NEPOOL stakeholders of market and credit risk concerns.

[40] *See* Lowell Testimony at 22-23.

make an initial determination of the incremental amount of FTRs made possible by the upgrade between defined receipt and delivery points related to the upgraded transmission elements. The entity funding the upgrade would have the opportunity, through an iterative determination process, to modify certain study parameters and to determine its specific IARR award based on the expected future value of the award. At the conclusion of the determination process, the exact amounts and receipt and delivery points are finalized. These would not change from auction to auction, although the dollar value of the IARR award in each auction would depend on the specific path clearing prices produced by the auction. Each of the existing QUAs would be converted into IARRs following this process. Each conversion is a one-time process.

No changes are being proposed to the rules approved by the LFTR Order with regard to how IARRs are determined, or in the fundamental manner in which they provide financial compensation to entities that fund upgrades to the transmission system. There are several modifications included for the purpose of making explicit some of the rights and obligations of IARR Holders that were not explicit in the 2008 rules. Specifically: (a) the rules clarify that if an IARR is funded by ongoing support payments, the holder of the IARRs must provide, on request of the ISO, documents that confirm that ongoing support payments are being made as required, and; (b) the holder of an IARR may transfer ownership to another Market Participant that is eligible to receive IARR payments, and that transferee would assume the obligation to make any required ongoing support payments.

3. No IARR Awards for Monthly Reconfiguration Auctions

The new rules clarify that IARRs only receive compensation in connection with auctions in which additional network capacity is made available beyond what was made available in previous auctions for that year due to the transmission upgrade associated with the IARR. This implies that there would be no IARR awards for the monthly reconfiguration auctions. Awards would be paid in association with both annual auction rounds and with all prompt month auctions. IARRs provide payment to the holder whenever the value based on the price difference between the sink nodes and the source nodes is positive, but unlike an FTR, does not require the holder to make a payment when the value is negative. Limiting the award associated with a specific auction by the fraction of network capacity made available in that auction is necessary to ensure that a transmission upgrade would never be compensated, in effect, for more than 100% of the upgrade capacity it provides.

4. No IARR Conversions to Incremental LFTRs At This Time

Finally, the IARR rules approved by the Commission in 2008 as part of the LTTR rules provide the holder with the right to convert an IARR into an Incremental LFTR ("ILFTR").[41]

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[41] An ILFTR is equivalent to an FTR that can only have a positive value, sometimes referred to as an "option FTR". Where IARRs provide the holder with compensation that is a share of auction revenues based on FTR auction prices, ILFTRs provide compensation to the holder based on nodal price differences (*i.e*. congestion) in the Day-Ahead Energy Market.

However, this conversion is not being provided for as part of these proposed FTR Enhancements. Providing support for ILFTRs would require significant enhancements to the FTR auction engine software, would significantly increase the scope of the FTR Enhancements, and would require significantly greater time, expense, and efforts. Implementation of ILFTRs will likely continue to be deferred until such time as the ISO is able to move forward with implementation of the full LFTR market design and associated software infrastructure, as previously approved.

E. Steps Necessary for the Implementation of the FTR Enhancements

The FTR Enhancements require changes to vendor-supported software systems used to administer the FTR auctions. The vendor already has reviewed the proposed design modifications and estimated the level of effort required to develop the necessary changes to the FTR software systems.

Additional changes are required to the software systems that handle market settlements (including FTRs, ARRs and IARRs) and financial assurance. These are supported by internal ISO resources. Preliminary planning for these changes has begun, primarily to ensure that the ISO can make efficient use of the internal development resources that must also support the FCM re-design initiative and the Order No. 745 demand response compensation initiative that will be ongoing during 2011 and 2012.

The ISO's initial effort to estimate the amount of work required and to plan for the availability of the specific resources needed to develop and test the systems that support the FTR Enhancements has determined that it is not possible to implement multiple rounds for the annual auction for calendar year 2012 or monthly reconfiguration auctions for every month in 2012. However, the ISO anticipates that annual auction rounds can be implemented for FTRs that will be effective for calendar year 2013.

Also, it may be possible to implement monthly reconfiguration auctions mid-year in 2012. The ISO is still evaluating this option. A mid-year implementation of monthly reconfiguration auctions should have no adverse impacts on market participants, as participation in a reconfiguration auction is purely voluntary. Those who desire to acquire FTRs month by month during the year may use the prompt month auctions which will operate in exactly the same manner as the current monthly FTR auctions.

Finally, as mentioned above, the PTOs are joining this filing in order to effectuate necessary changes to Schedule 21 that reflect the conversion to IARRs.[42]

IV. STAKEHOLDER PROCESS

The NEPOOL Markets Committee, at its March 8-9, 2011 meeting, voted with a 98.26% level of support to recommend the changes to Sections I and III of the ISO Tariff. The NEPOOL

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[42] *See, e.g.,* Schedule 21-Common Section II.7(d).

Transmission Committee, at its March 23, 2011 meeting, voted unanimously to recommend support for the IARR-related changes to the OATT, with no abstentions noted. The NEPOOL Participants Committee, at its April 1, 2011 meeting, voted unanimously to support the IARR-related changes to the OATT with one abstention, and voted unanimously, with two abstentions, to support the remainder of the FTR Enhancements as part of its Consent Agenda.[43]

V. REQUESTED EFFECTIVE DATE AND REQUEST FOR WAIVER

The Filing Parties request that the Commission permit the QUA to IARR conversion, including the changes to Schedule 21 reflecting the conversion, to become effective without suspension or hearing on July 13, 2011. Acceptance on or before that date will permit the ISO to implement the changes as soon as feasible, as contemplated by the ISO and its stakeholders.

As mentioned above, the ISO's initial planning effort has determined that IARRs can be implemented for the annual FTR auctions that will be conducted in the November 2011 timeframe for FTRs effective for the 2012 calendar year. There are good reasons to meet this implementation date: (a) Market Participants have previously requested early IARR implementation; and (b) there are significant, permanent administrative efficiencies in the ongoing use of ISO resources that are gained by replacing QUAs with IARRs. The conversion must be done for all of the existing QUAs and therefore, would require several months to complete. The original rules governing the conversion process were accepted by the Commission in 2008 and are not being modified by the FTR Enhancements. The conversion effort must be started promptly in order to be completed in time to support implementation for the 2012 calendar year. To that end, the ISO already has begun working with QUA holders to begin the process that would lead to conversion of QUAs to IARRs.

The Filing Parties request that the Commission permit the FTR auction changes to be effective (without change, suspension or hearing) on or after January 1, 2012, with two weeks' written notice of the actual effective date to be provided to the Commission by the ISO. Since the requested effective date is more than 120 days after the date of this filing, the Filing Parties request waiver of Section 35.3(a) of the Commission's regulations which specifies that all rate schedules or any part thereof must be filed with the Commission and posted not "more than one hundred-twenty days prior to the date on which the electric service is to commence and become

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[43] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. Although voted as a single motion, all recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's unanimous approval of the April 1, 2011 Consent Agenda included its support for the FTR Enhancements with the exception of the IARR-related changes to the OATT. The IARR-related changes to the OATT were considered separately because of the timing of the vote by the Transmission Committee, which occurred after the deadline for inclusion on the Consent Agenda. Furthermore, the two abstentions registered to the April 1, 2011 Consent Agenda were attributed to the inclusion on the Consent Agenda of the FTR Enhancements and another un-related item.

effective."[44] There is good cause to permit the requested waiver, as it will allow the ISO to more efficiently manage the implementation process and will ensure that the FTR auction changes become effective in an orderly and transparent manner as Market Participants prepare to participate in future FTR auctions.

The Filing Parties ask the Commission to issue an order within 60 days of this filing in order to provide regulatory certainty for Market Participants and to provide the ISO sufficient time for efficient development, testing, training, and deployment of implementing related business processes and software systems. Further, Market Participants would benefit from regulatory certainty as they prepare to comply with the FTR Enhancements.

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.[45] However, the FTR Enhancements are not traditional "rates," and the Filing Parties are not traditional investor-owned utilities. In light of these circumstances, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13, and request a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

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

- This transmittal letter;
- Blacklined ISO Tariff sections reflecting the revisions submitted in this filing;
- Clean ISO Tariff sections reflecting the revisions submitted in this filing;
- Testimony of Jonathan B. Lowell, Principal Analyst, Market Development, sponsored solely by the ISO; and
- List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities, to which a copy of this filing has been sent.

<u>35.13(b)(2)</u> - The Filing Parties request that the revisions become effective upon acceptance by the Commission as discussed in Section V of this transmittal letter.

<u>35.13(b)(3)</u> - 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

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[44] 18 C.F.R. §35.13(a) (2010).

[45] 18 C.F.R. § 35.13 (2010).

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

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

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

35.13(b)(6) - The ISO's, NEPOOL's, and PTOs' approval of the FTR Enhancements are evidenced by this filing. In addition, with respect to NEPOOL's support, as noted in Section IV of this transmittal letter, the FTR Enhancements reflect the outcome of the Participant Processes required by the Participants Agreement, and are supported by the NEPOOL Participants Committee.

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

VII. CONCLUSION

For the reasons stated herein, the Filing Parties respectfully request that the Commission accept the FTR Enhancements as filed, without condition, suspension, or hearing, to be effective on the dates requested in Section V of this transmittal letters.

Respectfully submitted,

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I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

ADR is alternative dispute resolution.

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

Affiliate, for purposes of Section I of the Tariff, is any person or entity which 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 and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Affiliate, for purposes of Section II of the Tariff, is, 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time

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

Backyard Generation is generation which interconnects directly with distribution facilities dedicated solely to load not designated as Network Load. Any distribution facilities which are shared with Network Load will not qualify.

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.

Billing Policy is defined in Exhibit ID to Section I of the Tariff.

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

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

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.3 of the Participants Agreement.

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

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

Capacity 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.

Capability Period means a period of time defined by the ISO for the purposes of rating and auditing resources. There are two Capability Periods, a Summer Capability Period and a Winter Capability Period. The dates defining the start and end of these periods are set forth in the ISO New England Manuals.

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

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

Capacity Carry-Forward Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.9 of Market Rule 1.

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

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

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

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

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

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5 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 of Market Rule 1.

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

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

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

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

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

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

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

Charge is defined in the ISO New England Billing Policy.

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

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

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

Commission is the Federal Energy Regulatory Commission.

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

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

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

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

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

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 or Long-Term Firm Point-to-Point Transmission 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.

Control Area, for purposes of Section II of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:
(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Council; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

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

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

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

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

Critical Peak Hours, for purposes of determining ODR Performance Hours, is defined as (i) those hours in which the projected hourly load, as shown in the ISO's next day Forecast System Load as published daily on ISO's website, for hours ending 1400 through 1700, Monday through Friday on non-holidays, during the months of June, July, and August, and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast, as determined by the ISO, for the applicable summer or winter season, and (ii) hours when the ISO activates Action Steps 6 or higher of Operating Procedure Number 4 in the Load Zone where the ODR resource is located.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

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 Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5 of Market Rule 1.

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time

Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

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

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Load Zone or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

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

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

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

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

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

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.

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.

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

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

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

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

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

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

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

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

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

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

Early Payment Shortfall Funding 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.

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

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

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

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.2 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

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

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

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

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

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

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

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

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

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

Emergency Service is the supply, from one neighboring control area operator to another, pursuant to the terms and conditions of applicable agreements for Emergency Energy, and any and all ancillary and transmission services associated with supplying such Emergency Energy.

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.

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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

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

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

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

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

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

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

EPSF Amount is defined in Section IV.B.2.4 of the Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

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

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 a purchase by a Market Participant of energy external to the New England Control Area or a sale by a Market Participant of energy external to the New England Control Area in the Day-Ahead Energy Market and/or Real-Time Energy Market or a through transaction scheduled by a Non-Market Participant in the Real-Time Energy Market.

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

Failure-to-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.

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

FCA Cleared Export Transaction is defined in Section III.1.10(f)(ii) of Market Rule 1.

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

FCACPZone is defined in Section III.9.8(b) of Market Rule 1.

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

Filing Entity is a PTO or PTOs submitting a proposal to the FERC to participate in, join, or become an ITC in accordance with Attachment M of the OATT.

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

Financial Assurance Policy for Market Participants is defined in Exhibit IA to Section I of the Tariff.

Financial Assurance Policy for Non-Market Participant Transmission Customers is defined in Exhibit IB to Section I of the Tariff.

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 reserved and/or scheduled between specified Points of Receipt and Delivery in accordance with the applicable procedure specified in Part II.C of the OATT or the Local Service Schedule.

Firm Transmission Service is service for Native Load Customers, firm Regional Network Service, service for Excepted Transactions and certain other transactions listed in Attachment G3, Firm MTF Service, Firm OTF Service, and firm service provided under the Local Service Schedules.

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

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

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

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

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

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

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

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

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4 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.9.1.2 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 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 that is used to calculate the Forward Reserve Threshold Price.

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

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

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

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

Forward Reserve Procurement Period is defined in Section III.9.1.1 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.9.5.1 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.

FRACPZone is defined in Section III.9.8(b) 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 Holder is an entity that acquires an FTR through the FTR Auction ~~or a subsequent bilateral arrangement pursuant~~ to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

Generator Maintenance Outage means the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the ISO New England Manuals and ISO New England Administrative Procedures.

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

Generator Planned Outage means the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the ISO in accordance with the ISO New England Manuals and ISO New England Administrative Procedures.

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 Participant is defined in the Participants Agreement.

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

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 or Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.5.8.3.

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

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

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 Objective Capabilities. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in Kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

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

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

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

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

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

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

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

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

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

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

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

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

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 FERC and a finding of the FERC that the transmission entity satisfies applicable independence requirements.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Interruption is defined, for purposes of Schedule 21, as a reduction in non-firm transmission service due to economic reasons.

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.

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

ITC 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.

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

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

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

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

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

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

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

Load-shifting means the movement of load between Market Participants, where one Market Participant's Real-Time Load Obligation decreases as load leaves to obtain service from another Market Participant whose Real-Time Load Obligation increases.

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

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 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 Parties are, with respect to a PTO's Local Service Schedule, the PTO and the Transmission Customer receiving service under the such Local Service Schedule.

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 Network Upgrades are modifications or additions to the Local Network of a PTO, made in accordance with Schedule 21, that are not Direct Assignment Facilities.

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

Local Second Contingency Protection Resource is defined in Section III.6.1 of Market Rule 1.

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

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

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under the OATT associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

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

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

Long-Term: A term of one year or more.

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.

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

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

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

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

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

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

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

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

Firm Load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

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

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

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

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

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

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

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

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

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the MTOA, 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 that is a signatory to an MTOA with the ISO.

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

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

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

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

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

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

Mitigation Measures is defined in Section III.A.1.1 of Appendix A of Market Rule 1.

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

Monthly Network Load is defined in Section II.21.2.

Monthly Peak: is defined in Section II.21.2.

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.

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

NEMA 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.

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.

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.

NERC is the North American Electric Reliability Council.

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section

II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Network Load located in the New England Control Area or other designated 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 Network Load.

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

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

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

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

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

Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

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

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4 of Market Rule 1.

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

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

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

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

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

New England 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.

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

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

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

Non-Dispatchable Qualifying Facility means a qualifying small power production facility or a qualifying cogeneration facility as defined in Section 201 of PURPA and the regulations of the Federal Energy Regulatory Commission under PURPA that is also either: (a) a daily cycle hydro or wind generating unit that cannot be dispatched by the ISO; or (b) a Special Qualifying Facility, which is a Non-Dispatchable Qualifying Facility (other than a daily cycle hydro or wind generating unit) for which a Market Participant has a contractual arrangement or regulatory obligation such that the Market Participant buyer has no authority or ability to schedule the hourly energy from the unit.

Non-Firm Point-To-Point Service is Point-To-Point Service that is subject to Curtailment or interruption under the circumstances specified in Schedule 18, Section 3.1(e) of the OATT.

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

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

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

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

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

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.

Operating Authority is defined pursuant to the MTOA or TOA 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 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).

Operating Reserve – Ten-Minute Non-Spinning Reserve Service (TMNSR) is the form of Ancillary Service described in Schedule 6.

Operating Reserve – Ten-Minute Spinning Reserve Service (TMSR) is the form of Ancillary Service described in Schedule 5.

Operating Reserve - Thirty-Minute Operating Reserve Service (TMOR) is the form of Ancillary Service described in Schedule 7.

Operations Date is February 1, 2005.

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

Other Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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

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

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

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

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

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.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Point(s) of Delivery is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt 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 is described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Pre-1997 PTF Rate is the transmission rate of a PTO determined in accordance with paragraph (5) of Schedule 9 to the OATT.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

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 Capacity Resource is a resource that has Qualified Capacity for a Capacity Commitment Period, or a portion thereof, that is not already obligated and that is seeking to acquire a Capacity Supply

Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

~~**Qualified Upgrade Awards** are revenues associated with the additional FTRs made possible in an FTR Auction by transmission upgrades, which increase transfer capability on the New England Transmission System, where such transmission upgrades are initially placed in service on or after March 1, 1997 and paid for by an entity and are not paid for through the Pool RNS Rate.~~

Reactive Supply and Voltage Control From Qualified Reactive Resources Service is the form of Ancillary Service described in Schedule 2.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, “Real-Time Demand Resource Dispatch Hours” shall be defined as those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report the output of one or more emergency generators as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a Load Zone or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. Beginning on June 1, 2011, Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose Federal, State and/or local air quality permits limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Accepted Electric Industry Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits is 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 Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Energy Obligation Credit is defined in Section III.10.5 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.8(b) of Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service 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.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3.

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual M 11.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission

Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Replacement Reserve means reserve other than TMSR, TMNSR or TMOR as defined in the ISO New England Manuals.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

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.

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.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

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.

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.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Sanctions Rule is defined in Section III.B of the Tariff (Appendix B to Market Rule 1).

Schedule, Schedules, Schedule 1, 2 and 3 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider is defined in Schedule 20A to Section II of this 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.

Scheduling, System Control and Dispatch Service (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.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Peak Demand Resource is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak

Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

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 Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment and that have elected Settlement Only Resource treatment as described in Section 5 of Attachment D to ISO New England Manual 20 – Installed Capacity.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.2.7.1.1.A.

Short-Term is a period of less than one year.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

Special Constraint Resources are Resources that provide Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the Net-Risk Adjusted Going Forward Costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is defined in the ISO New England Manuals.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Summer Season Demand Resource is a Demand Resource for which there is no or lower demand during winter peak associated with the end-use on which the Demand Resource measure is installed, and therefore the Winter Demand Reduction Value is zero or lower than the Summer Demand Reduction Value.

Supply Margin is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO , and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Through or Out Service means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission 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 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 Forced Outage means an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the ISO New England Manuals and ISO New England Administrative Procedures. A removal from service of a transmission facility at the request of the ISO to improve transmission capability shall not constitute a Transmission Forced Outage.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

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 Planned Outage means any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in the ISO New England Manuals and ISO New England Administrative Procedures.

Transmission Provider is defined in Section II of the Transmission, Markets and Services Tariff.

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 Section II of the Tariff, entered into by the Transmission Customer and the ISO for Regional Network Service, Through or Out Service or MTF Service; (B) entered into by the Transmission Customer with the PTO in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service; or (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of Section II of this Tariff. A Transmission Service Agreement shall be required for MTF Service and OTF Service, and shall be required for all other types of transmission service if the Transmission Customer is not executing an MPSA because it is not participating in the ISO New England Market.

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

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

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

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.6 of Market Rule 1 and the ISO New England Manuals.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is defined in the ISO New England Manuals.

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.2.7of Market Rule 1.

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II.19 Study Procedures For Regional Network Service Requests

II.19.1 Notice of Need for System Impact Study: After receiving a request for service, the ISO shall review the effect of the requested service on the reliability requirements to meet existing and pending obligations of any affected Transmission Owner(s) and on the obligations of the particular PTO(s) whose PTF facilities will be impacted by the proposed service and shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D to this OATT. If the ISO determines that a System Impact Study is necessary to accommodate the requested service, it shall as soon as practicable so inform the Eligible Customer and any affected Transmission Owner(s), and so inform the PTO(s) if the System Impact Study is to be performed by the PTO(s). If the likely result of the study is that a Direct Assignment Facility will be required, the study shall be performed by the affected PTO(s), subject to review by the ISO. In such cases, the ISO shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owner(s) for performing or participating in the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute a System Impact Study agreement and return it to the ISO within fifteen (15) days. If the

Eligible Customer elects not to execute a System Impact Study agreement, its Application shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) shall be returned with Interest

.

II.19.2 System Impact Study Agreement and Cost Reimbursement:

(a) The System Impact Study agreement, whether in the form detailed in Attachment I or in any other form that is mutually agreed to, will clearly specify the ISO's actual estimate of the actual cost, and time for completion of the System Impact Study. The actual charge shall not exceed the actual cost of the study. The System Impact Study shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF.

(b) If in response to multiple Eligible Customers requesting the service in relation to the same competitive solicitation, a single System Impact Study to accommodate the service, the costs of that study shall be prorated among the Eligible Customers.

(c) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owners on whose behalf the System Impact Study is conducted will record the cost of the System Impact Studies pursuant to Section II.8.5 of this OATT.

II.19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners and indirectly affected MTOs or OTOs will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study, if required, shall identify any system constraints, or the need for additional Direct Assignment Facilities or other facility additions or upgrades to provide the requested service. In the event that the ISO and the PTO designated to perform the study are unable to complete the required System Impact Study within such time period, the ISO shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due

diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for the Transmission Owners. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the New England Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen
(15) days of completion of the System Impact Study the Eligible Customer must execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s), or the Application shall be deemed terminated and withdrawn.

II.19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the PTF are needed to supply the Eligible Customer's service or to mitigate indirect impacts on the MTF or OTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a Facilities Study agreement, its Application shall be deemed withdrawn and its deposit, if any (less the reasonable Administrative Costs incurred by the ISO and any affected entities), shall be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s), will use due diligence to complete the required Facilities Study within a sixty-day period. If the ISO and any affected PTO(s) are unable to complete the Facilities Study in the allotted time period, the ISO shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Transmission Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected PTO(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Transmission Service

Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s) and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn. In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the ~~Qualified Upgrade Award~~Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the ~~Qualified Upgrade Award~~Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the ~~Qualified Upgrade Award~~Incremental ARRs.

II.19.5 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.19.6 Clustering of Regional Network Service Studies:

(a) Cluster Studies Request: The ISO, on its own initiative, or at the request of a group of Eligible Customers may consider studying specified requests for Regional Network Service in a cluster for the purpose of the System Impact Study and Facilities Study.

(b) Notice of Study Cluster: At the same time that the ISO informs the Eligible Customers that a System Impact Study or a Facilities Study is necessary to accommodate the requested Regional Network Service in accordance with Sections II.19.1 and II.19.4 of this OATT, the ISO will also notify the Eligible Customers, either in response to their joint request or on its own initiative that (i) studying specific multiple requests for Regional Network Service in a cluster may result in a more efficient study process or may result in a more efficient and economic construction of the new facilities or upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study, as specified in Sections II.19.3 and II.19.4 of this OATT. If an Eligible Customer chooses not to have its Regional Network Request studied as part of the cluster, it shall have ten (10) days from the date that the ISO notifies the Eligible Customer of its intent to study specific multiple requests for Regional Network Service in a cluster to inform the ISO of its determination to have its request studied separately.

(c) Cluster Study Process and Procedures: The ISO shall follow the process and procedures set forth in Sections II.19.1 through II.19.4 of this OATT with respect to the performance of the System Impact Study and the Facilities Study, except that:

(i) For clustered studies, a single study agreement either in the form detailed in Attachment I or Attachment J of this OATT, as applicable, or in any other form that is mutually agreed to, will be tendered by the ISO to all Eligible Customers, which is to be entered into by all the Eligible Customers and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s), and pursuant to which the Eligible Customers shall agree to reimburse the ISO and affected PTO(s) for performing the required study. The costs of that study will be divided equally among the Eligible Customers, unless otherwise agreed to by the ISO and the Eligible Customers.

(ii) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the date on which all Eligible Customers in the cluster have executed the applicable study agreement. If the ISO and any affected PTO(s) are unable to complete the applicable study in the allotted time period, the ISO shall notify the Eligible Customers and provide an estimate of the time needed to complete the study and an explanation of the reasons that additional time is required to complete the study.

(iii) In the event that ISO determines that additions or upgrades to the PTF are required to accommodate the requests for Regional Network Service that are studied as part of a cluster, the costs of the Transmission Upgrades will be allocated to each Eligible Customer whose request was studied as part of the cluster based on each Eligible Customer's share of the total megawatts of service requested, unless otherwise agreed to by the ISO and the Eligible Customers.

(iv) At the request of a Transmission Customer whose Regional Network Service request was studied as part of a cluster, the ISO shall provide a non-binding estimate of the ~~Qualified Upgrade Award~~Incremental ARRs, if any, resulting from the construction of new facilities based on the Transmission Customer's share of the costs of the new facilities. The Transmission Customer shall be responsible for the cost of any study required to determine the ~~Qualified Upgrade Award~~Incremental ARRs.

II.31 Service Availability

II.31.1 General Conditions: Through or Out Service on the PTF shall be available to any Transmission Customer that has met the applicable requirements of Section II.32.

II.31.2 Determination of Available Transfer Capability: A description of the ISO's specific methodology for assessing available transfer capability posted on the OASIS (Section II.5 of this OATT) is contained in Attachment C of this OATT.

II.31.3 Initiating Service in the Absence of an Executed Transmission Service Agreement: If the ISO and the Transmission Customer requesting Point-To-Point Service, who has not executed an MPSA or on whose behalf the ISO has not filed an unexecuted MPSA with the Commission, cannot agree on all the terms and conditions of the applicable Transmission Service Agreement, the ISO will file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the ISO to file, an unexecuted Transmission Service Agreement containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO) for such requested transmission service. The service will be commenced subject to the Transmission Customer agreeing to (i) pay whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this OATT including providing appropriate security deposits in accordance with the terms of Section II.34.3.

II.31.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the New England Transmission System: If a Transmission Customer requests that the PTF be expanded or modified, one or more PTOs or other entities will be designated to use due diligence to expand or modify the PTF to increase transfer capability, provided that the Transmission Customer agrees to compensate the PTO(s) or other entities that will be responsible for the construction of any new facilities or upgrades for the costs of such new facilities or upgrades pursuant to the terms of Section II.38. The ISO and the designated PTOs or other entities will conform to Good Utility Practice and the planning obligations in Attachment K in determining the need for new transmission facilities or upgrades and in coordinating the design and construction of such facilities. This obligation applies only to those facilities that the designated PTO(s) or other entities have the right to expand or modify.

II.31.5 Deferral of Service: Any ~~Qualified Upgrade Award~~ Incremental ARR associated with new transmission facilities or upgrades shall be subject to completion of construction of those transmission facilities and upgrades and to such upgrades being placed in service.

II.31.6 Real Power Losses: Real power losses are associated with all transmission service. The ISO, Transmission Owners and Schedule 20A Service Providers are not obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices pursuant to Market Rule 1. Real power losses across MTF shall be allocated in accordance with Schedule 18 of this OATT and real power losses across OTF shall be allocated in accordance with Schedule 20 of this OATT.

II.31.7 Load Shedding: To the extent that a system contingency exists on the PTF, MTF or OTF and the ISO determines that it is necessary for the Transmission Owners and the Transmission Customers to shed load, the Parties shall shed load in accordance with the ISO System Rules or in accordance with other mutually agreed-to provisions.

II.34 Study Procedures For Through or Out Service Requests

II.34.1 Notice of Need for System Impact Study: A request for Through or Out Service will not normally require a System Impact Study. An Eligible Customer may specifically request that the ISO conduct a System Impact Study for an Elective Transmission Upgrade pursuant to Section II.47.2 of this OATT (a "Study Request"). After receiving a request to study an Elective Transmission Upgrade, the ISO will review the effect of the proposed service or upgrade on the reliability requirements to meet existing and pending obligations of the Transmission Customers, and the obligations of any affected Transmission Owner(s) whose facilities will be impacted by the proposed service and determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D. After receiving a Request, the ISO will within thirty (30) days of receipt of a Study Request, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owners for performing or participating in the required System Impact Study. Before a Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact Study agreement, its request shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) in connection with the Application), will be returned with Interest.

II.34.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study agreement shall clearly specify the ISO's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF and indirectly affected MTF or OTF of the customer request for an Elective Transmission Upgrade.

(ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.

(iii) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owner will record the cost of the System Impact Studies pursuant to Section II.8.5 to this OATT.

II.34.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study shall identify the need for additional Direct Assignment Facilities or facility additions or upgrades required to comply with the Eligible Customer's request. In the event that the required System Impact Study cannot be completed within such time period, the ISO will so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required study and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer that is not a Market Participant as it uses when completing studies for an Eligible Customer that is a Market Participant. The ISO will notify the Eligible Customer immediately upon completion of the System Impact Study.

II.34.4 Facilities Study Procedures: After a System Impact Study indicates that additions or upgrades to the PTF or indirectly affected MTF or OTF are needed to accommodate the Eligible Customer's Study Request, the ISO, within thirty (30) days of the completion of the System Impact Study, will tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) or other entity designated by the ISO for performing any required Facilities Study. If the Eligible Customer wants the ISO to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study agreement, its Study Request shall be deemed withdrawn and its deposit, if any (less the reasonable administrative costs incurred by the ISO and any affected entity in connection with the Application), will be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s) or other designated entity will use due diligence to cause the required Facilities Study to be completed within a sixty-day period. If a Facilities Study cannot be completed in the allotted time period, the ISO will notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, or (ii) the Eligible Customer's appropriate share of the cost of any required upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Owner(s)or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of the new facilities or upgrades and consistent with relevant commercial practices, as established by the Uniform Commercial Code.

In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the ~~Qualified Upgrade Award~~Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the ~~Qualified Upgrade Award~~Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the ~~Qualified Upgrade Award~~Incremental ARRs.

II.34.5 Facilities Study Modifications: Any change in design arising from inability to site or construct proposed facilities will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the affected Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades and that significantly affect the final cost of the new facilities or upgrades to be charged to the Eligible Customer pursuant to the provisions of this OATT.

II.34.6 Due Diligence in Completing New Facilities: The ISO will use due diligence to designate PTOs or other entities to add necessary facilities or upgrade the PTF, MTF or OTF within a reasonable time. A PTO or other entity will have no obligation to upgrade its existing or planned transmission system if doing so would impair system reliability or otherwise impair or degrade existing firm service. Nothing in this OATT shall be deemed to create an obligation to build upgrades that an entity does not otherwise have by contract, law or regulation.

II.34.7 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO to tender at one time, together with the results of required studies, an "Expedited Study Request" pursuant to which the Eligible Customer would agree to pay for all costs incurred pursuant to the terms of this OATT. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Study Request covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying the need for facility additions or upgrades and costs to be incurred in providing the requested service. While the ISO, on behalf of the PTO(s) or other entities that will be responsible for constructing the new facilities or upgrades, agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer shall agree in writing to pay for all costs incurred pursuant to the provisions of this OATT. The Eligible Customer shall execute and return such an Expedited Study Request within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

II.34.8 Penalties for Failure to Meet Study Deadlines: Sections 34.3 and 34.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.43 Auction Revenue Rights and ~~Qualified Upgrade Award~~Incremental ARRs:

A system of Auction Revenue Rights and ~~Qualified Upgrade Award~~Incremental ARRs shall be implemented pursuant to Appendix C of Market Rule 1.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

(a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Point-To-Point Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the

PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.

(b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22 and 23 to this OATT.

(c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade may be required or proposed pursuant to a Regional System Plan. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with Schedule 12 of this OATT.

(d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission Owners and the operators of the affected Local Control Centers with such information as is necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive.
Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated ~~Qualified Upgrade Award~~Incremental ARRs equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 11 or 12 to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

SCHEDULE 21 - LOCAL SERVICE

This Schedule 21 contains the main substantive provisions applicable to Local Service. It includes common PTO rates, terms and conditions for Local Point-to-Point Service and Local Network Service and PTO-specific Local Service Schedules. Retail service is not subject to this Schedule 21 unless specifically provided for in the PTO's Local Service Schedule. The rates, terms and conditions for interconnection service to generators with total generating capacity of greater than 20 MW are set forth in Schedule 22. The rates, terms and conditions for interconnection service to generators with total generating capacity of 20 MW and less are set forth in Schedule 23. To the extent applicable, the rates, terms and conditions for load interconnections are set forth under the PTO-specific Local Service Schedules.

All Transmission Customers taking Local Service shall be subject to and comply with the rates, terms and conditions of this Schedule 21 as well as any applicable Local Service Schedule. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 21 and/or an applicable Local Service Schedule, the rate, term or condition in this Schedule 21 and/or the applicable Local Service Schedule shall govern.

With the exception of waivers specified in certain PTO-specific Local Service Schedules, the following NAESB Standards are hereby incorporated by reference in this Schedule 21 to the extent that the requirements therein apply to the PTOs:

Business Practice Standards relating to Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009;

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009).

The Participating Transmission Owners have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER11-23-000.

Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Manual Time Error Correction (WEQ-006, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007);

Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009). *To the extent that this standard does apply to an individual PTO, the incorporation of this standard shall be addressed within the respective PTO-specific Local Service Schedule.*

The PTOs will perform their functions under this Schedule 21 and the Local Service Schedules in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

Pre-Confirmed Request: Is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Point-to-Point Service.

Pre-RTO Local Service Agreements [1]: A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Firm or Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that was in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement" as defined to Section II.1 of the OATT) shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Pre-RTO Local Service Agreement.

A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Pre-RTO Local Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing pre-RTO Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

RTO Local Service Agreements: For Local Service Agreements with an effective date on or after February 1, 2005 (an "RTO Local Service Agreement" as defined to Section II.1 of the OATT) a Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of its existing Local Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the Transmission Customer's existing Local Service Agreement may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement. A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its

[1] LSAs as defined in Section II.1 of the OATT do not include Excepted Transaction Agreements under Attachments G-1, G-2 and G-3 of the OATT.

existing RTO Local Service Agreement, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing RTO Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission only, with a contract term of five years or more), have the right to continue to take Local Service from the PTO when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the PTO or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the PTO's Local Network cannot accommodate all of the requests for Local Service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the PTO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Local Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Local Service Agreements subject to a right of first refusal entered into prior to the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service agreements with five years or more left in their terms as of the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890.

Force Majeure: Neither the ISO, a Transmission Owner nor a Customer will be considered in default as to any obligation under the Tariff 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 or under a Service Agreement. However, an entity whose performance under the Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under the Tariff, and shall promptly notify the ISO, the

Transmission Owner or the Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

Liability: The ISO shall not be liable for money damages or other compensation to the Customer for actions or omissions by the ISO in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by the ISO is found to result from its gross negligence or willful misconduct. A Transmission Owner shall not be liable for money damages or other compensation to the Customer for action or omissions by such Transmission Owner in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from it gross negligence or willful misconduct. To the extent the Customer has claims against the ISO or a Transmission Owner, the Customer may only look to the assets of the ISO or a 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 the ISO or a Transmission Owner or Affiliate of either who, the Customer acknowledges and agrees, have no personal or other liability for obligations of the ISO or a Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either. In no event shall the ISO, a Transmission Owner or any 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 the Tariff or any Service Agreement thereunder. Notwithstanding the foregoing, nothing in this section shall diminish a Customer's obligations under Section I.5.3 of the Tariff or under Schedule 21 of the OATT.

Indemnification: Each Customer shall at all times indemnify, defend, and save harmless the ISO and the Transmission Owners and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO or Transmission Owners under the Tariff or any Service Agreement thereunder, any bankruptcy filings made by a Customer, or the actions or omissions of the Customer in connection with the Tariff or any Service Agreement thereunder, except in case of the ISO, gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents, and, in the case of a Transmission Owner, the gross negligence or willful misconduct by such 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 each Customer to indemnify the ISO and Transmission Owners shall be several, and not joint or joint and several.

I. LOCAL POINT-TO-POINT SERVICE

Preamble

Eligible Customers seeking Local Point-To-Point Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Firm and Non-Firm Local Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Local Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

A Local Point-To-Point Service Customer 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 PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

1) Nature of Firm Local Point-To-Point Service

a) Term: The minimum term of Firm Local Point-To-Point Service shall be one day and the maximum term shall be specified in the Local Service Agreement.

b) Reservation Priority: Local Long-Term Firm Point-To-Point Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Local Short-Term Firm Point-To-Point Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Requests for Local Short-Term Point-to-Point Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request. If the Local Network becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Local Short-Term Firm Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.1.h of this Schedule 21) from being notified by the PTO of a longer-term competing request for Local Short-Term Firm Point-To-Point Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 21. Firm Local Point-To-Point Service will always have a reservation priority over Non-Firm Local Point-To-Point Service under the Tariff. All Local Long-Term Firm Point-To-Point Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in the Local Service Schedules of this Schedule 21.

c) **Use of Firm Local Point-to-Point Service by the PTO**: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of the Local Point-To-Point Service to make Third-Party Sales.

d) **Service Agreements**: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Transmission Customer Obligations for Facility Additions Costs: In cases where the PTO, in consultation with the ISO, determines that the Local Network is not capable of providing Firm Local Point-To-Point Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Local Point-To-Point Service, or (2) interfering with the PTO's ability to meet prior firm contractual commitments to others, the PTO will be obligated to expand or upgrade its Local Network pursuant to the terms of Section I.3.d of this Schedule 21. The Transmission Customer must agree to compensate the PTO for any necessary transmission facility additions pursuant to the terms of Section I.14 of this Schedule 21. Any Local Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Local Service Agreement prior to initiating service.

f) Curtailment of Firm Local Point-To-Point Service: In the event that a Curtailment on the PTO's Local Network, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the PTO will curtail service to Network Customers and Transmission Customers taking Firm Local Point-To-Point Service on a basis comparable to the curtailment of service to the PTO's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Point-To-Point Service and Local Network Service. When the PTO determines that an electrical emergency exists on the Non-PTF and the PTO implements emergency procedures to Curtail Firm Local Service, the Transmission Customer shall make the required reductions upon request of the PTO. The PTO reserves the right to Curtail, in whole or in part, any Local Service when, in the PTO's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Local Network. The PTO will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. Penalties for failure to Curtail shall be assessed pursuant to the applicable Local Service Schedule.

g) Classification of Firm Local Point-To-Point Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section I.10.a of this Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section I.10.b of this Schedule 21.

(ii) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the PTO's Local Network. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(iii) The PTO shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. For Long-Term Firm Point-To-Point Service, each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Local Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. For Short-Term Firm Point-To-Point Service, Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties. For Long-Term Firm Point-To-Point Service, each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. For Short-Term Firm Point-To-Point Service, Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of the applicable Local Service Schedule. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in the applicable Local Service Schedule. The Local Service Schedule shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved.

h) Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service must be submitted to the PTO no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their service requests at a common point of receipt into units of 10 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO, and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

2) Nature of Non-Firm Local Point-To-Point Service

a) Term: Non-Firm Local Point-To-Point Service will be available for periods ranging from one (1) hour to one (1) month. However, a purchaser of Non-Firm Local Point-To-Point Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section I.6.c of this Schedule 21.

b) Reservation Priority: Non-Firm Local Point-To-Point Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers, Excepted Transactions and other Transmission Customers taking Local Long-Term and Local Short-Term Firm Point-To-Point Service. Individual Local Service Schedules may contain other applicable services. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Requests. In the event the Local Network is constrained, competing requests of the same pre-confirmation status and equal duration will be prioritized based on the highest price offered by the Transmission Customer for the Transmission Service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis, i.e., in the chronological sequence in which each customer has requested service. Transmission Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Local Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Local Point-To-Point Service after notification by the PTO; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.f of this Schedule 21) for Non-Firm Local Point-To-Point Service other than hourly transactions after notification by the PTO. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the OATT.

c) **Use of Non-Firm Local Point-To-Point Service by the PTO**: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under (i) agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of Non-Firm Local Point-To-Point Service to make Third-Party Sales.

d) **Service Agreements**: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) **Classification of Non-Firm Local Point-To-Point Service**: The PTO and the ISO undertake no obligation under the Tariff to plan the Local Network in order to have sufficient capacity for Non-Firm Local Point-To-Point Service. Parties requesting Non-Firm Local Point-To-Point Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its non-firm capacity reservation. Non-Firm Local Point-To-Point Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

f) **Scheduling of Non-Firm Local Point-To-Point Service**: Schedules for Non-Firm Local Point-To-Point Service must be submitted to the PTO no later than 2:00 p.m. of the day prior to commencement of such service. Schedules submitted after these times will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 10 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

g) **Curtailment or Interruption of Service**: The PTO reserves the right to Curtail, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Local Network. The PTO reserves the right to Interrupt, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Local Transmission Service, (2) a request for Non-Firm Local Point-To-Point Service of greater duration, (3) a request for Non-Firm Local Point-To-Point Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The PTO also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Local Point-To-Point Service under the Tariff. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Local Point-To-Point Service under the Tariff. The PTO will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice and in accordance with the applicable Local Service Schedule. Penalties for failure to Curtail or Interrupt shall be assessed pursuant to the applicable Local Service Schedule.

3) Service Availability

a) General Conditions: The PTO will provide Firm Local and Non-Firm Local Point-To-Point Service to any Transmission Customer that has met the requirements of Section I.4 of this Schedule 21.

b) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

c) Initiating Service in the Absence of an Executed Service Agreement: If the PTO and the Transmission Customer requesting Firm Local or Non-Firm Local Point-To-Point Service cannot agree on all of the terms and conditions of the Local Service Agreement, the ISO shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to both the PTO and the ISO directing the ISO to file, an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service. The PTO shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the PTO at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section I.5.c of this Schedule 21.

d) Obligation to Provide Transmission Service that Requires Expansion or Modification of the Local Network: If the PTO, in consultation with the ISO, determines that a Completed Application for Firm Local Point-To-Point Service cannot be accommodated because of insufficient capability on the Local Network, the PTO will use due diligence to expand or modify its Local Network to provide the requested Firm Local Point-To-Point Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the PTO for such costs. The PTO, in consultation with the ISO, will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation of the PTO to expand or modify its Local Network obligation to provide the requested Firm Local Point-To-Point Service applies only to those facilities that the PTO has the right to expand or modify.

e) Deferral of Service: The PTO may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Local Point-To-Point Service whenever the PTO determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

f) Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

g) Real Power Losses: Real Power Losses are associated with all transmission service. Neither the ISO nor the PTOs are obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

h) Load Shedding: Load Shedding shall occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

4) Transmission Customer Responsibilities

a) Conditions Required of Transmission Customers: Firm Local and Non-Firm Local Point-To-Point Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service;

(ii) The Transmission Customer meets the creditworthiness procedures in Attachment L to the applicable PTO's Local Service Schedule;

(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the PTO prior to the time service commences;

(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer, whether or not the Transmission Customer takes service for the full term of its reservation;

(v) The Transmission Customer provides the information required by the PTO's planning process established in Attachment K; and

(vi) The Transmission Customer has executed a Local Service Agreement or has requested the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21.

b) Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Eligible Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO and the PTO, notification to the ISO and the PTO identifying such systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this Schedule 21 on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the ISO and the PTO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of its existing Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement may be required. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Firm Local Point-to-Point Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) Transmission Customers who wish to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) an Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: A request for Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to the ISO at least sixty (60) days in advance of the calendar month in which service is to commence. The PTO will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the PTO and the Eligible Customer within the time constraints provided in the applicable Local Service Schedule. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The ISO and the PTO will treat this information as confidential except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to the Information Policy;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTO's Local Network; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Service upon acceptance on OASIS by the PTO that can provide the requested Local Service; and

(x) Any additional information required by the PTO’s planning process established in Attachment K.

The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) **Deposit**: Except as is otherwise provided in the Local Service Schedule, a Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, in the Local Service Schedule or, in the case of requests for service arising in connection with losing bidders, in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the PTO in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the PTO if the PTO is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Local Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the PTO to the extent such costs have not already been recovered by the PTO from the Eligible Customer. The PTO will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section I.5.c of this Schedule 21. If a Local Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Local Service Agreement. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

f) **Notice of Deficient Application**: If an Application fails to meet the requirements of the Tariff, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. The PTO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application. The PTO shall return any deposit, with interest, to the Eligible Customer. Upon receipt of a new or revised Application that fully complies with the requirements of this Schedule 21, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

g) Response to a Completed Application: Following receipt of a Completed Application for Firm Local Point-To-Point Service, the PTO shall make a determination of available transfer capability as required in Section I.3.b of this Schedule 21. Within twenty-five (25) days after the date of receipt of a Completed Application, the PTO shall notify the ISO either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. The ISO shall so notify the Eligible Customer within five (5) days of the ISO's receipt of such notice from the PTO. Responses by the PTO and the ISO must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

h) Execution of Service Agreement: Whenever the PTO, in consultation with the ISO, determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section I.7 of this Schedule 21 will govern the execution of a Local Service Agreement. Failure of an Eligible Customer to execute and return the Local Service Agreement or request the filing of an unexecuted service agreement pursuant to Section I.3.c of this Schedule 21 within fifteen (15) days after the Local Service Agreement is tendered will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

i) Extensions for Commencement of Service: The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying to the PTO a non-refundable annual reservation fee equal to one-month's charge for Firm Local Point-To-Point Service for each year or fraction thereof within 15 days of notifying the PTO it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Local Point-To-Point Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement may be required. The Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify the existing Non-Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required.

Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21.

(ii) A Transmission Customer who wishes to request an upgrade (i.e., increase MWs served) beyond the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: Eligible Customers seeking Non-Firm Local Point-To-Point Service must submit a Completed Application to the ISO. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the service priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the ISO and the PTO also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service;

(vii) The electrical location of the ultimate load; and

(viii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Service.

The ISO and the PTO will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to the ISO New England Information Policy. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) Reservation of Non-Firm Local Point-To-Point Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable.

f) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

7) Additional Study Procedures For Firm Local Point-To-Point Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Firm Local Point-To-Point Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedules.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same geographical or electrically interconnected area requesting that a System Impact Study for Local Service be clustered, the PTO will cluster such multiple requests if it can reasonably do so. The costs of that study shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers.

(v) Once a clustered study is initiated by the PTO, as evidenced by an executed System Impact Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in Section 7(b)(iv) above, unless otherwise agreed to by the parties to such System Impact Study Agreement.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints identified with specificity by a transmission element or flowgate, and additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the

Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on facilities other than Non-PTF, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers. Once a clustered study is initiated by the PTO, as evidenced by an executed Facilities Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in this Section 7(d) above, unless otherwise agreed to by the parties to such Facilities Study Agreement. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Transmission Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

e) **Facilities Study Modifications**: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the

PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Firm Local Point-To-Point Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) Partial Interim Service: If the PTO determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Local Point-To-Point Service, the PTO nonetheless shall be obligated to offer and provide the portion of the requested Firm Local Point-To-Point Service that can be accommodated without addition of any facilities. However, the PTO shall not be obligated to provide the incremental amount of requested Firm Local Point-To-Point Service that requires the addition of facilities or upgrades to the Local Network until such facilities or upgrades have been placed in service.

h) Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO (in consultation with the PTO) to tender at one time, together with the results of required studies, an "Expedited Local Service Agreement" pursuant to which the Eligible Customer would agree to compensate the PTO for all costs incurred. In order to exercise this option, the Eligible Customer shall request in writing an expedited Local Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the PTO agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the PTO for all costs incurred. The Eligible Customer shall execute and return such an Expedited Local Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

i) Penalties for Failure to Meet Study Deadlines: Sections I.7.c and I.7.d of this Schedule 21 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The PTO is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the PTO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the PTO shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The PTO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The PTO is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the PTO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the PTO completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the PTO takes to complete that study beyond the 60-day deadline.

j) Claims or Disputes: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

8) Procedures if The PTO is Unable to Complete New Transmission Facilities for Firm Local Point-To-Point Service

a) Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the PTO shall promptly notify the Transmission Customer. In such circumstances, the PTO shall within, thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The PTO also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the PTO that is reasonably needed by the Transmission Customer to evaluate any alternatives.

b) Alternatives to the Original Facility Additions: When the review process of Section I.8.a of this Schedule 21 determines that one or more alternatives exist to the originally planned construction project, the PTO shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request that the ISO file a revised Local Service Agreement for Firm Local Point-To-Point Service. If the alternative approach solely involves Non-Firm Local Point-To-Point Service, the PTO shall so inform the ISO, and the ISO (in consultation with the PTO) shall thereafter promptly tender to the Transmission Customer a Local Service Agreement for Non-Firm Local Point-To-Point Service providing for the service. In the event the PTO concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures of Section I.6 of the Tariff.

c) Refund Obligation for Unfinished Facility Additions: If the PTO and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested Firm Local Point-To-Point Service cannot be provided out of existing capability, the obligation to provide the requested service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the ISO and the PTO through the time construction was suspended, including costs for removal of unfinished facilities and any ongoing operating expenses of the unfinished facilities until they are removed.

9) Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

a) Responsibility for Third-Party System Additions: The PTO shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The PTO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

b) Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified, and if such upgrades further require the addition of transmission facilities on other systems, the PTO shall have the right to coordinate construction on its own system with the construction required by others. The PTO, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The PTO shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the PTO of its intent to defer construction, the Transmission Customer may challenge the decision in accordance with Section I.6 of the Tariff.

10) Changes in Service Specifications

a) Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Local Point-To-Point Service from a PTO may request transmission service on a non-firm basis over Receipt and Delivery Points of the same PTO other than those specified in the Local Service Agreement ("Secondary Receipt and Delivery Points") in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Local Point-To-Point Service charge or executing a new Local Service Agreement, subject to the following conditions. A Transmission Customer may request a modification to its Non-Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.6. (a) and (b), as appropriate.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the PTO on behalf of its Native Load Customers.

(b) The sum of all Firm Local and Non-Firm Local Point-To-Point Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Local Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Local Point-To-Point Service at the Receipt and Delivery Points specified in the relevant Local Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Local Point-To-Point Service under the Tariff. However, all other requirements of this Schedule 21 (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

b) Modification On a Firm Basis: Any request by a Transmission Customer to modify the Firm Local Point-to-Point Service it receives from a PTO to obtain service between different Receipt and Delivery Points on the Local Network of the same PTO on a firm basis shall be treated as a new request for service, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Local Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Local Service Agreement. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.5. (a) and (b), as appropriate.

11) Sale or Assignment of Transmission Service

a) Procedures for Assignment or Transfer of Service: A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Local Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Local Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee. The Assignee must execute a service agreement with the PTO governing reassignments of transmission service prior to the date on which the reassigned service commences. The PTO shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Local Service Agreement with the PTO or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the PTO or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Local Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of the Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the PTO pursuant to Section I.1.b of this Schedule 21. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO must be made pursuant to sections I.5. (a) and (b) and I.6. (a) and (b), as appropriate.

b) Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Local Service Agreement, the PTO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the New England Transmission System or the PTO's distribution system, as applicable. The Assignee shall compensate the ISO and/or the PTO, as applicable, for performing any System Impact Study needed to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Local Service Agreement, except as specifically agreed to by the PTO and Reseller through an amendment to the Local Service Agreement

c) Information on Assignment or Transfer of Service: In accordance with Section I.11 of this Schedule 21 and applicable provisions of the Local Service Schedules, all sales or assignments of capacity must be conducted through or otherwise posted on the PTO's OASIS on or before the date the reassigned Local Point-to-Point Service commences and are subject to Section I.11.a of this Schedule 21. Resellers may also use the OASIS to post transmission capacity available for resale.

12) Metering and Power Factor Correction at Receipt and Delivery Points(s)

a) Transmission Customer Obligations: Unless otherwise provided in the applicable Local Service Schedule, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted through Local Point-To-Point Service and to communicate the information to the PTO, Local Control Centers and the ISO. Such equipment shall remain the property of the Transmission Customer.

b) PTO Access to Metering Data: The PTO shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Local Service Agreement.

c) Power Factor: In accordance with Good Utility Practice and any applicable Local Service Schedule, the Transmission Customer is required to maintain a power factor within the same range as the PTO. The power factor requirements are specified in the Local Service Agreement where applicable.

13) Compensation for Local Point-To-Point Service:
Rates for Firm Local and Non-Firm Local Point-To-Point Service are set forth in the Local Service Schedules.

14) Compensation for New Facilities Costs:
Whenever a System Impact Study performed in connection with the provision of Firm Local Point-To-Point Service identifies the need for new facilities, the Transmission Customer shall be responsible for the costs of the new facilities to the extent consistent with Commission policy.

II. LOCAL NETWORK SERVICE

Preamble
Eligible Customers seeking Local Network Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Local Network Service will be provided pursuant to the applicable rates, terms and conditions set forth below.

1) Nature of Local Network Service
Local Network Service is provided to Network Customers to serve their loads. It includes transmission service for the delivery to a Network Customer of its energy and capacity from Network Resources and delivery to or by Network Customers of energy and capacity from New England Markets transactions.

2) Availability of Local Network Service

a) Eligibility to Receive Local Network Service: Transmission Customers taking Regional Network Service must also take Local Service.

b) **Compliance With State Law**: A Network Customer 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 PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

c) **Scope of Service**: Local Network Service allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Local and Regional Network Load and any additional load that may be designated pursuant to the Tariff. The Network Customer taking Local Network Service must obtain or provide Ancillary Services.

d) **PTO Responsibilities**: The PTO in accordance with the TOA will plan, construct, operate and maintain its Local Network in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Local Network Service. Each PTO, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer. This information must be consistent with the information used by the PTO to calculate available transfer capability. The PTO in accordance with the TOA shall include the Network Customer's Local Network Load in Local Network planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver Network Resources to serve the Network Customer's Local and Regional Network Load on a basis comparable to the PTO's delivery of its own generating and purchased resources to its Native Load Customers.

e) **Comparability of Service**: Local Network Service will be provided to the Network Customer for the delivery of energy and/or capacity from its resources to serve its Local and Regional Network Loads on a basis that is comparable to the PTO's use of its Local Network to reliably serve Native Load Customers.

f) **Real Power Losses**: Real Power Losses are associated with all transmission service. The PTOs are not obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

g) **Secondary Service**: The Network Customer may use the Local Network to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as available basis, at no additional charge. Secondary service shall not require the filing of an Application for Local Network Service under Section II of this Schedule 21. However, all other requirements of Section II of this Schedule 21 (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point To Point Service.

h) Restrictions on Use of Service: The Network Customer shall not use Local Network Service for (i) sales of capacity and energy to non designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Local Network Service shall use Local Point To Point Service for any Third Party Sale, which requires use of the Local Network. The PTO shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Local Network Service or secondary service pursuant to Section II.2.g of this Schedule 21 to facilitate a wholesale sale that does not serve Local Network Load.

3) Initiating Service

a) Condition Precedent for Receiving Service: Local Network Service shall be provided only if the following conditions are satisfied by the Eligible Customer: (i) the Eligible Customer completes an Application to the ISO for service, (ii) the Eligible Customer and the PTO complete the technical arrangements, and (iii) the Eligible Customer executes a Local Service Agreement with the PTO and the ISO or requests in writing that the ISO file an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service with the Commission.

4) Procedures for Arranging Local Network Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service

Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement may be required. The Transmission Customer shall contact the PTO to discuss and, if appropriate, modify the existing Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternative Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Local Service Agreement under this Schedule 21, shall not be required execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional Local or Regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of the existing Local Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application Procedures: An Eligible Customer requesting Local Network Service must submit an Application, with a deposit equal to the charge for one month of service, unless another charge is specified in the applicable Local Service Schedule, to the ISO as far as possible in advance of the month in which service is to commence. Completed Applications for Local Network Service will be assigned a reservation priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A description of the Local Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each substation at the same transmission voltage level. The description should include a ten-year forecast of summer and winter load resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Local Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten-year projection), which shall include, for each Network Resource, if the description is not otherwise available to the ISO and the PTOs:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit

- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable dispatch price ($/MWH), consistent with Market Rule 1, for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the New England Control Area, where only a portion of unit output is designated as a Network Resource
- Description of external purchased power designated as a Network Resource including source of supply, control area location, transmission arrangements and delivery point(s);

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the ISO and the PTOs
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Local Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- ten-year projection of system expansions or upgrades
- transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested service. The minimum term for service is one year; and

(viii) Any additional information required of the Transmission Customer as specified in the PTO's planning process established in Attachment K.

Unless the Eligible Customer and the ISO agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Local Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this Section, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. Wherever possible, the ISO and the PTO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application without prejudice to the Eligible Customer, who may thereafter file a new or revised Application that fully complies with the requirements of this Section. The Eligible Customer will be assigned a new reservation priority consistent with the date of the new or revised Application. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

d) Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until the PTO and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Service Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Non-PTF. The PTO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

e) Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Non-PTF to the Network Customer. The Network Customer shall be solely responsible for constructing or installing and operating and maintaining all facilities on the Network Customer's side of each such delivery point or interconnection.

f) Filing of Service Agreement: The ISO shall file Local Service Agreements with the Commission in compliance with applicable Commission regulations.

5) Network Resources

a) Designation of Network Resources: The Network Customer shall designate those Network Resources which are owned, purchased or leased by it. The Network Resources so designated may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Local Network Load on a non-interruptible basis. Any owned, purchased or leased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Compliance Effective Date shall be deemed to continue to be so owned, purchased or leased by it until the Network Customer informs the ISO and the PTO of a change.

b) **Designation of New Network Resources**: The Network Customer shall identify any new Network Resources which are owned, purchased or leased by it with as much advance notice as practicable. A designation of any new Network Resource as owned, purchased or leased by the Customer must be made by a notice to the ISO and the PTO.

c) **Termination of Network Resources**: The Network Customer may terminate the designation of all or part of a Network Resource as owned, purchased or leased by it at any time but shall provide notification to the ISO and the PTO as soon as reasonably practicable.

d) **Network Customer Redispatch Obligation**: As a condition to receiving Local Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO and the PTO. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate External Transactions. The Network Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

e) **Transmission Arrangements for Network Resources Not Physically Interconnected with the PTO's Non-PTF**: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the PTO's Non-PTF. The applicable PTO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

f) **Limitation on Designation of Network Resources**: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

g) Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the PTO's Local Network may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the PTO to serve all of its power and transmission customers. For facilities added by the Network Customer subsequent to the effective date of a Final Rule in RM05-25-000, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the PTO's facilities; provided however, the Local Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the PTO, would be eligible for inclusion in the PTO's annual transmission revenue requirement as specified in the PTO's respective Local Service Schedule. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

6) Designation of Local Network Load

a) Local Network Load: The Network Customer must designate the individual Local Network Loads which it expects to have served through Local Network Service. The Local Network Loads shall be specified in the Local Service Agreement.

b) New Local Network Loads Within the New England Control Area: The Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable of the designation of new Local Network Load that will be added to the Non-PTF. A designation of new Local Network Load must be made through a modification of service pursuant to a new Application. The PTO will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Local Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Local Network Load shall be determined in accordance with the procedures provided in this Schedule 21 and shall be charged to the Network Customer in accordance with Commission policy and this Schedule 21.

c) Local Network Load Not Physically Interconnected with the PTO: This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with the PTO's Non-PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the Local Network, the Network Customer shall have the option of

(1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point To Point Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section the request must be made through a modification of service pursuant to a new Application.

d) New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Non-PTF and a Local Network Load, the Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable.

e) Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (the addition of a new Network Resource, if any, or designation of a new Local Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the PTOs and charged to the Network Customer as reflected in the applicable Local Service Agreement or other appropriate agreement. However, the PTO must treat any requested change in Local Network Service in a non-discriminatory manner.

f) Annual Load and Resource Information Updates: The Network Customer shall provide the ISO and the PTO with annual updates of Local Network Load and Network Resource forecasts consistent with those included in its Application including, but not limited to, any information provided under Section II.3.b of this Schedule 21 pursuant to the PTO's planning process in Attachment K. The Network Customer also shall provide the ISO and the PTO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Local Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the PTO to provide reliable service.

7) Additional Study Procedures For Local Network Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Local Network Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedule.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same electrically interconnected area requesting clustering of system Impact Study analysis for Local Service, the PTO will accommodate such multiple requests if it can reasonable do so. The costs of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis.

c) **System Impact Study Procedures**: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section II.3.a of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) **Facilities Study Procedures**: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis. For a service request to remain a Completed

Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Eligible Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study shall, if requested by the Eligible Customer, contain a non-binding estimate from the ISO of the ~~Qualified Upgrade Awards~~ Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the ~~Qualified Upgrade Awards~~ Incremental ARRs, if any, resulting from the upgrade or expansion.

e) Facilities Study Modifications: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Local Network Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) **Claims or Disputes**: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

h) **Penalties for Failure to Meet Study Deadlines**: Section I.7.i of this Schedule 21 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Section I of this Schedule 21. These same requirements and penalties apply to service under Section II of this Schedule 21.

8) **Load Shedding and Curtailments**

a) **Procedures**: The PTO shall establish Load Shedding and Curtailment procedures (consistent with those of the ISO and the Local Control Center) with the objective of responding to contingencies on the Non-PTF. The PTO will notify all affected Local Network Service Customers in a timely manner of any scheduled Curtailment.

b) **Transmission Constraints**: During any period when a PTO or the Local Control Center determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, the PTO or the Local Control Center will so inform the ISO. The ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the New England Transmission System can be maintained by redispatching resources, The ISO will initiate procedures to redispatch all resources on a least-cost basis without regard to the ownership of such resources.

c) **Cost Responsibility for Relieving Transmission Constraints**: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customer will bear the costs of such redispatch in accordance with Market Rule 1.

d) **Curtailments of Scheduled Deliveries**: If a transmission constraint on the Non-PTF cannot be relieved through the implementation of least-cost redispatch procedures and the PTO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with the terms of the Tariff.

e) **Allocation of Curtailments**: The ISO, the Transmission Owner or the Local Control Center shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service and OTF Service and/or Through or Out Service and Network Customers on a non-discriminatory basis. Notwithstanding the preceding provisions of this Section, External Transactions shall be scheduled and curtailed in accordance with Section II.44 of the OATT.

f) **Load Shedding**: Load Shedding also may occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

g) **System Reliability**: Notwithstanding any other provisions of this Schedule, The ISO, the PTO and the Local Control Centers reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of service without liability on the part of the ISO, the PTO or the Local Control Centers for the purpose of making necessary adjustments to, changes in, or repairs on the PTO's lines, substations and facilities, and in cases where the continuance of service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Non-PTF or on any other system(s) directly or indirectly interconnected with the Non-PTF, the ISO, the PTO and the Local Control Centers, consistent with Good Utility Practice, also may effect a Curtailment of service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO, the PTO or the Local Control Centers will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to the PTO's use of the New England Transmission System on behalf of their Native Load Customers. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) **Rates and Charges**

The Network Customer shall pay all applicable charges for Local Network Service set forth in this Schedule 21, including the Local Service Schedules, and for any Direct Assignment Facilities and its share of the cost of any required Local Network Upgrades and applicable study costs consistent with Commission policy, along with any additional charges imposed under the Tariff. In the event the Network Customer serves Local Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for each Local Network.

10) Determination of Network Customer's Monthly Network Load

For purposes of Local Network Service, the Network Customer's "Monthly Network Load" shall be determined in accordance with the applicable Local Service Schedule.

11) Operating Arrangements

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the terms of the Tariff. The terms and conditions under which the Network Customer taking Local Network Service shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service shall be specified in Section II.22 of the Tariff and/or the Local Service Schedules.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of ______________, is entered into, by and between ________________ , a _________________organized and existing under the laws of the State/Commonwealth of ______________ ("Transmission Owner"), _____________ , a _________________organized and existing under the laws of the State/Commonwealth of ______________ ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

__ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:

____

____

____

Transmission Owner:

____

____

____

The ISO:

____

____

____

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”) is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission’s rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act

and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Specifications for Local Network Service.

   a. Term of Service:

   b. List of Network Resources and Point(s) of Receipt:

   c. Description of capacity and energy to be transmitted:

   d. Description of Local Network Load:

   e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

   f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

q. Additional terms and conditions:

4. Planned work schedule.

Estimated Time Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

   c. Point(s) of Receipt:

   d. Delivering Party:

   e. Point(s) of Delivery:

   f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:________________________ ________________ ______________

Name Title Date

____

Print Name

Transmission Owner:

By:________________________ ________________ ______________

Name Title Date

____

Print Name

The ISO:

By:________________________ ________________ ______________

Name Title Date

____Print Name

SCHEDULE 21

ATTACHMENT A-1

Form of Local Service Agreement For The Resale, Reassignment or Transfer of Point-To-Point Transmission Service

1.0 This LOCAL SERVICE AGREEMENT, dated as of ______________, is entered into, by and between _______________ , a ________________organized and existing under the laws of the State/Commonwealth of _____________ ("Transmission Owner"), ____________ , a ________________organized and existing under the laws of the State/Commonwealth of _____________ ("Assignee") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Assignee, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

2.0 The Assignee has been determined by the Transmission Owner to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Local Service Agreement shall be subject to the terms and conditions of Part I of Schedule 21 and the Transmission Owner's Local Service Schedule of Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.11.a of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.11.b of this Tariff.

4.0 The Transmission Owner shall credit the Reseller for the price reflected in the Assignee's Local Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Local Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Owner:

____

____

____

The ISO:

____

____

____

Assignee:

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Owner:

By:____________________ ________________________ _______________

Print Name: Title: Date:

The ISO:

By:____________________ ________________________ _______________

Print Name: Title: Date:

Assignee:

By:____________________ ________________________ ________________

Print Name: Title: Date:

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ___________________________________

Start Date: ____

Termination Date: _____________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Owner including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:___________________________________

Delivering Party:_______________________________________

4.0 Point(s) of Delivery:__________________________________

Receiving Party:_______________________________________

5.0 Maximum amount of reassigned capacity: __________________

6.0 Designation of party(ies) subject to reciprocal service obligation:____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:____

____

(Name of Transmission Owner) Open Access Transmission Tariff

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:____________________

____

8.4 Ancillary Services Charges: ______________________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

III.5 Transmission Congestion Revenue & Credits Calculation

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

III.5.1.1 Calculation by ISO.

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

III.5.1.2 General.

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

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation.

Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Congestion Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using Point-to-Point Transmission Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility.

Except as provided in Section III.A.8.4 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

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

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

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

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

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders.

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

III.5.2.5 Calculation of Transmission Congestion Credits.

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

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

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

III.5.2.6 Distribution of Excess Congestion Revenue.

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

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

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

III.7.1.1 Auction Period and Scope of Auctions.

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

(b) ~~Following the initial auctions described above, FTR auctions shall be held on both an annual and monthly basis. Fifty percent of the feasible FTRs that can be made available with a term of one year shall be made available in the annual FTR Auction. After the annual FTR Auction has been conducted, the remaining feasible FTRs, each having a term of one month, shall be made available in the monthly FTR Auctions. Within two years from the March 1, 2003, the ISO will evaluate making available FTRs with a term of more than one year (in one-year increments).~~ The annual FTR Auction shall be conducted for FTRs effective for a single calendar year in two sequential rounds. Twenty-five percent of the available network capacity shall be available for the initial round of the annual FTR Auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round shall be made available during the second round of the annual FTR Auction.

(c) The ISO shall conduct monthly FTR Auctions, after the completion of the annual FTR Auction, every month. A monthly FTR shall be effective for a single full calendar month. The monthly FTR Auctions shall include separate auctions for every remaining month in the calendar year. FTRs shall be made available for monthly auctions as follows:

(i) When FTRs for a month are auctioned for the final time, all FTRs that remain feasible will be made available, after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

(ii) For all other monthly auctions all FTRs that remain feasible with fifty percent of the network capacity available will be made available after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

III.7.1.2 ~~Frequency and Time of FTR Auctions~~FTR Auctions Assumptions.

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

~~(b) Monthly auctions: The bid and offer period shall open beginning fifteen business days before the first business day of the month preceding the period in which the FTRs are to be effective for a five business day auction-quoting period that closes at noon on the fifth business day~~For annual FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 90 days prior to the first effective day of the FTRs to be auctioned. For monthly FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 40 days prior to the first effective day of the FTRs to be auctioned.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

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

III.7.2.2 Specified Locations.

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

III.7.2.3 Transmission Congestion Revenues.

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

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

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

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

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

III.7.3.5 Offers and Bids.

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

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

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

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

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction.~~ The base FTRs model also will include estimated uncompensated parallel flows into each interface point of the New England Control Area and estimated scheduled transmission outages~~ The base FTR model for the annual FTR Auction will reflect the network topology and transmission operating limits in effect at the time the annual FTR Auction is conducted, adjusted for estimated scheduled transmission outages. Monthly FTR Auctions (other than for the first month in the series of remaining months in the calendar year) shall utilize the same base network topology and transmission operating limits as used in the annual FTR Auction. The auction for the first month in the series of remaining months in the calendar year shall utilize the then current network topology and transmission operating limits, as adjusted for currently estimated scheduled transmission outages and outages of individual generating units to the extent that such outages impact voltage or stability limits. The base FTR models also will include estimated uncompensated parallel flows into each interface point of the New England Control Area.

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

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

III.7.3.7 Announcement of Winners and Prices.

~~(a) Within four business days after the close of a monthly auction and six business days after the close of an annual or initial long-term auction~~

(a) After the close of the first round of the annual FTR Auction, in accordance with the schedule published in the auction assumptions and prior to the open of the bidding window for the final-round annual auctions, the ISO shall post the auction prices and FTRs cleared between eligible bidding locations, as specified in Section III.7.2.2, excluding the identity of the winning bidder. The identities of winning bidders and the quantities of FTRs cleared by individual bidders in the first round of the annual auction will not be published until the close of the final round of the annual FTR Auction.

After the close of the final round of the annual FTR Auction, the ISO shall post, in accordance with the schedule set forth in the auction assumptions and prior to the open of the bidding window for monthly auctions, the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the annual auction and the price at which each FTR was awarded.

~~(b)~~

(b) After the close of the monthly FTR Auction process, in accordance with the schedule set forth in the auction assumptions and prior to the effective date of the auctioned FTRs, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTR~~s~~ was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (~~c~~d) and (~~d~~e).

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

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

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

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

III.7.3.8 Auction Settlements.

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

III.7.3.9 Allocation of Auction Revenues.

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

III.7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages, network model-related changes, and expected configuration of transmission facilities ~~and outages of individual generating units to the extent that such outages impact voltage or stability limits and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction~~in accordance with Section III.7.3.6(a).. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

~~**III.7.3.13 [Reserved.]**~~

~~**III.7.3.14 Temporary FTR Surcharge**.~~

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

SECTION III

MARKET RULE 1

APPENDIX C

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

APPENDIX C

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

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AUCTION REVENUE RIGHTS AND ~~QUALIFIED UPGRADE AWARDS~~INCREMENTAL ARRs

III.C.1 Introduction.

Auction Revenue Rights ("ARRs") are rights to receive FTR Auction Revenues from the sale of FTRs other than FTRs sold by FTR Holders. ~~Qualified Upgrade Awards~~ Incremental ARRs are rights to receive FTR Auction Revenues associated with transmission system upgrades, as provided in Section III.C.8. ARRs shall be determined and allocated to Congestion Paying LSEs, Transmission Customers and NEMA LSEs (including any of the foregoing that are parties to Excepted Transactions that are included in the list of transactions specified in Attachments G and G-2 of the Transmission, Markets and Services Tariff), using a four-stage process as described below (the "ARR Allocation"). Congestion Paying LSEs that are Asset Related Demands or Dispatchable Asset Related Demands will receive ARR allocations based on the specific relevant Node for each Asset.

Auction Revenue Rights are determined at the completion of each month to distribute the net FTR Auction Revenues (which excludes FTR Auction Revenues attributable to FTRs sold at auction by FTR Holders) associated with that month, including a monthly share of all net revenues from annual FTR Auctions that include that particular month based on the number of days in the month divided by the number of days in the year, and including the net auction revenues from all monthly auctions for FTRs effective for that particular month. The ARR determination for revenues associated with annual on-peak or off-peak FTR Auctions shall be based on the auction prices resulting from the specific annual on-peak or off-peak auction. The ARR determination for revenues associated with monthly on-peak FTR Auctions shall be based on the auction prices in the final on-peak auction for the month. The ARR determination for revenues associated with monthly off-peak FTR Auctions shall be based on the auction prices in the final off-peak auction for the month.

III.C.2 First Stage ARR Allocation

III.C.2.1 Excepted Transactions.

In the first stage of each ARR Allocation, each entity serving load to which energy is delivered or making an External Transaction sale pursuant to an Excepted Transaction included in the list of transactions specified in Section II.41 of Section II of the Transmission, Markets and Services Tariff, and which is the party responsible for paying Congestion Cost associated with energy purchased under the Excepted

Transaction shall have the option to be allocated ARRs from the generator to the location of the load or External Node. Alternatively, each seller delivering energy pursuant to an Excepted Transaction to an entity serving load or making an External Transaction sale and in which the seller is the party responsible for paying Congestion Cost associated with energy purchased under the Excepted Transaction shall have the option to be allocated ARRs from the generation source to the location of the load or External Node. For an Excepted Transaction which is not an External Transaction, if the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction does not elect to be allocated ARRs under Section III.C.2.1, then the ARRs associated with the destination Node(s) of the load served by such Excepted Transaction shall be allocated pursuant to Section III.C.2.2.
The party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction which is an External Transaction will retain its existing contract rights for physical scheduling of such transaction pursuant to Section II of the Transmission, Markets and Services Tariff until such party irrevocably elects to be allocated ARRs under this Section III.C.2. Such irrevocable election shall mean that the party may not revert to using its contract rights for physical scheduling. For an Excepted Transaction which is an External Transaction purchase, the party may request to be allocated ARRs, prior to each FTR Auction, either pursuant to Section III.C.2.1 or pursuant to Section III.C.2.2. For an Excepted Transaction which is an External Transaction, if the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction does not elect to be allocated ARRs under Section III.C.2.1, then the ARRs associated with the destination Node(s) of the load served by such Excepted Transaction shall be allocated pursuant to Section III.C.2.2. For an Excepted Transaction which is an External Transaction sale, ARRs will be allocated pursuant to Section III.C.2.1.

III.C.2.1.1 Requesting Allocation of First Stage ARRs for Excepted Transactions.

In order to be eligible to receive ARRs in association with an Excepted Transaction, each entity to which energy is delivered pursuant to an Excepted Transaction or which delivers energy pursuant to an Excepted Transaction must request that it be allocated ARRs pursuant to this Section III.C.2.1 and in accordance with the ISO New England Manuals and ISO New England Administrative Procedures prior to each FTR Auction.

III.C.2.1.2 Specification of First Stage ARRs for Excepted Transactions.

The first stage ARR Allocation to an entity serving load to which energy is delivered or making an External Transaction sale pursuant to an Excepted Transaction who makes such a request shall be equal to the number of megawatts of energy to be delivered to that customer under the Excepted Transaction. The origin Node(s) or External Node(s) for those ARRs shall match the generation source for any such Excepted Transaction and the destination Node(s) for those ARRs shall match the location: (i) of the load served by those Excepted Transactions or (ii) of the External Node if the Excepted Transaction is an External Transaction sale. The first stage ARR Allocation to an entity selling energy to an entity serving load or making an External Transaction sale to which energy is delivered pursuant to an Excepted Transaction who makes such a request shall be equal to the number of megawatts of energy to be delivered by that selling entity under the Excepted Transaction. The origin Node(s) or External Node(s) for those ARRs shall match the generation source for any such Excepted Transaction and the destination Node(s) for those ARRs shall match the location: (i) of the load served by those Excepted Transactions or (ii) of the External Node if the Excepted Transaction is an External Transaction sale. Each entity shall be entitled to make requests for ARRs under the terms of this section until the Excepted Transaction has terminated, or ten years from the SMD Effective Date, whichever is earlier.

III.C.2.2 Transmission Customers and Congestion Paying LSEs.

ARRs shall be allocated to each Congestion Paying LSE and Transmission Customer from each generating Resource and tie line source in proportion to the capacity of the generator and tie line source and in proportion to the loads in the network model for the FTR Auction for the ~~month~~ period being settled.

~~For each Long-Term Firm Through or Out Service reservation, a load equal to the number of megawatts of Reserved Capacity for such reservation shall be modeled at the appropriate External Node.~~ The generator or tie line source and load associated with each Excepted Transaction shall be reduced by the MW quantity of the Excepted Transaction. The determination of the first stage ARR Allocation to Transmission Customers and Congestion Paying LSEs shall be performed using the following formula:

$$N_{ijt} = G_{it} * (L_{jt}/L_t),$$

where:

N_{ijt} = the amount of ARRs from Node or External Node i to Node or External Node j for the ~~month~~ period being settled t;

G_{it} = the total rated capacity for month *t* of generators or the capacity during ~~month~~ period *t* of tie line capacity located at Node *i*;

L_{jt}= the load at Node *j* from the network model used for the FTR Auction for ~~month~~ period *t*, updated as appropriate, less any portion of that load which is associated with Excepted Transactions as described above; and

L_t = total load from the network model used for the FTR Auction for ~~month~~ period t, updated as appropriate, less any portion of that load which is associated with all Excepted Transactions as described above.

The total quantity of ARRs assigned to load pursuant to this Section III.C.2.2 in ~~month~~ period t shall be:

$$\sum_i \sum_j N_{ijt}$$

III.C.3 Second Stage of ARR Allocation

III.C.3.1 In General.

The amount of ARRs allocated to each entity in the first stage of each ARR Allocation may be modified in the second stage of that ARR Allocation. The second stage of each ARR Allocation shall determine the final allocation of ARRs to all ARR Holders for that FTR Auction, except for NEMA LSEs. Allocations of ARRs to NEMA LSEs may be modified in the third and fourth stages of the ARR Allocation for each FTR Auction.

III.C.3.2. The Second Stage Allocation Procedure.

The second stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, and the termination or expiration of Excepted Transactions. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures. For each FTR Auction:

Step 1: Begin with the combination of all ARRs included in the first-stage ARR Allocation described in Section III.C.2.

Step 2: ~~Hold~~ Determine a value for each ARR using the ~~FTR Auction~~ on-peak or off-peak auction prices, as applicable, pursuant to Section III. C.1.

Step 3: Through the following steps, eliminate ARRs having a negative value in the FTR Auction and then reduce the set of remaining ARRs defined in Step 1 proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.

3(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction.

3(b): Test whether the ARRs identified in Step 3(a) are simultaneously feasible.

3(c): If the ARRs identified in Step 3(a) are simultaneously feasible, go to Step 4.

3(d): If the ARRs identified in Step 3(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 3(a).

3(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the ARRs defined in Step 3(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all ARRs defined in Step 3(a) that increase flows over this constraint until the constraint is relieved.

3(f): Test whether the ARRs identified in Step 3(e) are simultaneously feasible. If the set of ARRs defined in Step 3(e) is simultaneously feasible, proceed to Step 4.

3(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 3(e).

3(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the ARRs defined in Step 3(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all ARRs defined in Step 3(e) that increase flows over this constraint until the constraint is relieved.

3(i) Repeat Steps 3(f) through 3(h) as necessary until a simultaneously feasible set of ARRs is obtained.

3(j) If as a result of the application of Steps 3(e) through 3(i) any of the constraints over which ARRs were reduced in Steps 3(e) through 3(i) is no longer binding, ARRs defined in Step 3(a) that have been reduced in Steps 3(e) through 3(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

The allocation process ends here if NEMA is not constrained and the ARRs allocated at the conclusion of Step 3(j) constitute the final allocation of ARRs.

Step 4. The ARR Allocation determined in the preceding steps shall be divided into two sets: ARRs allocated to entities that are not NEMA LSEs, and ARRs allocated to NEMA LSEs.

III.C.4 Third Stage of ARR Allocation

III.C.4.1 In General.

The ARRs allocated to NEMA LSEs, as determined in the first two stages of each ARR Allocation, may be modified further in the third and fourth stages of the ARR Allocation. The third and fourth stages of any ARR Allocation shall not change the amount or origin Nodes or External Nodes or destination Nodes of any ARRs allocated to entities that are not NEMA LSEs as of the conclusion of the second stage of that ARR Allocation.

III.C.4.2 Definition of Stage 3 ARRs.

For the purposes of this stage, a set of "Stage 3 ARRs" shall be defined as follows: Certain NEMA LSEs which have long-term purchase contracts in effect as of November 1, 1999 for generation resources with delivery points in NEMA, excluding long-term purchase contracts covered by Excepted Transactions, ("NEMA Contracts") shall be allocated Stage 3 ARRs.

III.C.4.2.1 Verification of NEMA Contracts.

The NEMA Contracts for these NEMA LSEs' respective generation resources and entitlements, which entitle them to Stage 3 ARRs subject to verification that the NEMA Contracts meet the criteria specified in Section III.C.4.2, are listed in ***Exhibit 1*** to this Appendix C. Each NEMA LSE listed in ***Exhibit 1*** shall provide by October 1, 2000 to the ISO and shall make available upon request to each NEMA LSE, copies of its NEMA Contract(s) in the form that such contracts existed as of November 1, 1999, together with copies of any subsequent modifications or amendments, any notices of termination, and any notices or elections shortening the term or reducing the amount of power to be purchased under its NEMA Contract(s). For as long as a NEMA LSE listed in ***Exhibit 1*** has a right to request Stage 3 ARRs, it shall have an ongoing obligation to provide, in a timely manner, each NEMA LSE and the ISO with copies of any further modifications or amendments, any transfers to another entity of the responsibility for paying for the Congestion Cost any notices of termination, and any notices or elections shortening the term or reducing the amount of power to be purchased under its NEMA Contract.

III.C.4.2.2. Specification of Stage 3 ARRs.

The amount of Stage 3 ARRs that will be allocated to each NEMA LSE shall be equal to the sum of the megawatts of entitlement specified in each NEMA LSE's NEMA Contract(s) calculated based on the winter capability period (the period from the beginning of October through the end of May) capacity during months of the winter capability period and the summer capability period (the period from the beginning of June through the end of September) capacity during the months of the summer capability period subject to the limitation that the Stage 3 ARRs allocated to each NEMA LSE shall not exceed that NEMA LSE's Real-Time Load Obligation excluding External Transaction sales at the time of the coincident peak for the New England Control Area for the ~~month~~ period being settled. The origin Node(s) or External Node(s) for the Stage 3 ARRs allocated to NEMA LSEs shall match the Node(s) or External Node(s) where energy was purchased in association with the NEMA Contracts listed in Exhibit 1, and the destination Node(s) for the Stage 3 ARRs allocated to NEMA LSEs shall match the location of the load served by that NEMA LSE in association with that contract.

III.C.4.2.3. Requesting Allocation of Stage 3 ARRs for NEMA Contracts.

The NEMA LSEs identified in ***Exhibit 1*** to this Appendix C shall be entitled to make requests for Stage 3 ARRs under the terms of this section until the earlier of the expiration of the term of each of its NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999, or until NEMA is no longer constrained. To the extent that such a NEMA LSE transfers to another entity the responsibility for paying for the Congestion Cost resulting from the NEMA LSE's NEMA Contract, the entity assuming such responsibility shall receive the entitlement to the NEMA LSE's Stage 3 ARRs in lieu of the NEMA LSE receiving that entitlement.

III.C.4.3. The Third Stage Allocation Procedure.

The third stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, reductions in or resale of purchase amounts under NEMA Contracts, and the termination of the NEMA Contract(s) or expiration of the term of the NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures.

Step 1: Begin with the set of all Stage 3 ARRs.

Step 2: Through the following steps, eliminate Stage 3 ARRs having a negative value in the FTR Auction and then reduce the set of remaining Stage 3 ARRs proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.

2(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction. Then add the set of all non-NEMA ARRs as determined in Step 4 of Stage 2 to the remaining Stage 3 ARRs.

2(b): Test whether the ARRs identified in Step 2(a) are simultaneously feasible.

2(c): If the ARRs identified in Step 2(a) are simultaneously feasible, go to Step 3.

2(d): If the ARRs identified in Step 2(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(a).

2(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 3 ARRs defined in Step 2(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 3 ARRs defined in Step 2(a) that increase flows over this constraint until the constraint is relieved.

2(f): Test whether the ARRs identified in Step 2(e) are simultaneously feasible. If the set of ARRs defined in Step 2(e) is simultaneously feasible, proceed to Step 3.

2(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(e).

2(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 3 ARRs defined in Step 2(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 3 ARRs defined in Step 2(e) that increase flows over this constraint until the constraint is relieved.

2(i) Repeat Steps 2(f) through 2(h) as necessary until a simultaneously feasible set of ARRs is obtained.

2(j) If as a result of the application of Steps 2(e) through 2(i) any of the constraints over which ARRs were reduced in Steps 2(e) through 2(i) is no longer binding, ARRs defined in Step 2(a) that have been reduced in Steps 2(e) through 2(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

Step 3. Remove the non-NEMA ARRs. The remaining ARRs will be the ARRs for the NEMA Contracts.

III.C.5 Fourth Stage of ARR Allocation Procedure

III.C.5.1 In General.

The fourth stage of the ARR Allocation shall determine the final allocation of ARRs for a given FTR Auction. The fourth stage shall only affect the allocation of ARRs to NEMA LSEs.

III.C.5.2 Definition of "Stage 4 ARRs".

For the purposes of this step, a set of "Stage 4 ARRs" shall be defined. The determination of the fourth stage ARR Allocation to NEMA LSEs shall be performed using the following formula:

$$N_{ijt} = A_{ijt} * X_{jt}$$

where:

N_{ijt} = the amount of Stage 4 ARRs from Node or External Node *i* to the load at NEMA Node *j* (from the network model used for the FTR Auction) for the ~~month~~ period being settled *t*;

A_{ijt} = the amount of ARRs from Node or External Node *i* to NEMA that had been allocated to the load at NEMA Node *j* for ~~month~~ period *t* as of the conclusion of the second stage of the ARR Allocation; and

X_{jt} = the ratio of load at NEMA Node *j* from the network model used for the FTR Auction for ~~month~~ period *t*, less any portion of that load which is associated with NEMA Contracts as described above, to the total load at NEMA Node *j* from the network model used for the FTR Auction for ~~month~~ period *t*.

III.C.5.3 The Fourth Stage Allocation Procedure.

The fourth stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, reductions in purchase amounts under NEMA Contracts, and the termination of the NEMA Contract(s) or expiration of the term of the NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures.

Step 1: Begin with the set of all Stage 4 ARRs.

Step 2: Through the following steps, eliminate Stage 4 ARRs having a negative value in the FTR Auction and then reduce the set of remaining Stage 4 ARRs proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.2(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction. Then add the set of all non-NEMA ARRs and all ARRs for NEMA Contracts to the remaining Stage 4 ARRs.

2(b): Test whether the ARRs identified in Step 2(a) are simultaneously feasible.

2(c): If the ARRs identified in Step 2(a) are simultaneously feasible, go to Step 3.

2(d): If the ARRs identified in Step 2(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(a).

2(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 4 ARRs defined in Step 2(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 4 ARRs defined in Step 2(a) that increase flows over this constraint until the constraint is relieved.

2(f): Test whether the ARRs identified in Step 2(e) are simultaneously feasible. If the set of ARRs defined in Step 2(e) is simultaneously feasible, proceed to Step 3.

2(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(e).

2(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 4 ARRs defined in Step 2(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 4 ARRs defined in Step 2(e) that increase flows over this constraint until the constraint is relieved.

2(i) Repeat Steps 2(f) through 2(h) as necessary until a simultaneously feasible set of ARRs is obtained.

2(j) If as a result of the application of Steps 2(e) through 2(i) any of the constraints over which ARRs were reduced in Steps 2(e) through 2(i) is no longer binding, ARRs defined in Step 2(a) that have been reduced in Steps 2(e) through 2(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

Step 3. The remaining ARRs constitute the final allocation of ARRs. Holders of ARRs in this allocation shall be deemed ARR Holders.

III.C.6 Distribution of FTR Auction Revenues

Each ARR Holder shall be entitled to receive a monthly share of ~~the~~ FTR Auction Revenues ~~from each annual, monthly, or other~~ (excluding FTR Auction ~~reflecting~~ Revenues attributable to FTRs sold at auction by FTR Holders) from each FTR Auction. FTR Auction Revenues are determined by the value of each auctioned FTR as described in ~~that auction of FTRs, other than those~~ Section.7.3.6. FTR Auction Revenues shall not include the value of FTRs sold by FTR Holders, corresponding to its ARRs, whether or not such specific FTRs are actually sold. The determination of the FTRs awarded in each FTR Auction shall be subject to a simultaneous feasibility test in accordance with Section III.7 of Market Rule 1. The amount of feasible FTRs available in the FTR Auction (and the corresponding FTR Auction Revenues and payments to ARR Holders and ~~entities eligible for Qualified Upgrade Awards~~ Incremental ARR Holders) will vary depending on transmission system conditions as modeled. ~~Entities eligible for Qualified Upgrade Awards~~Incremental ARR Holders, described in Sections III.C.1and III.C.8, shall be entitled to receive a monthly share of the FTR Auction Revenues reflecting the incremental value~~, as determined in the auction,~~ of ~~additional FTRs made possible by~~ such transmission upgrade, as determined in accordance with Section III.C.8.

Following the distribution of FTR Auction Revenues for ~~Qualified Upgrade~~ Incremental ARR ~~Awards~~awards, the ISO shall distribute the remaining monthly share of the FTR Auction Revenues. The distribution of FTR Auction Revenues is ~~as~~ described below:

Step 1: For a specified destination ~~Node or External~~ Node, the amount of ARRs (quantified in megawatts) received in the final allocation of ARRs with specified origin Nodes or External Nodes and such destination Node ~~or External Node~~ shall be multiplied by the difference in the clearing prices determined in that FTR Auction for the same origin Nodes or External Nodes and such destination Node ~~or External Node~~ as the ARRs.

Step 2: A dollar value shall be allocated to each Load Zone~~ and to each External Node~~. The dollar value to be allocated to each Load Zone shall be calculated by summing Step 1 over all of the Nodes in the Load Zone.

Step 3: A dollar value shall be allocated to each Asset Related Demand and Dispatchable Asset Related Demand within a Load Zone (excluding station service and pumps), which is settled at a Node and are not included in the Load Zone's Real-Time Load Obligation. The allocation is calculated using the dollar value of the ARRs for the specific Node associated with each Asset Related Demand and Dispatchable Asset Related Demand. The allocated dollar values are then subtracted from the dollar value previously allocated to the Load Zone in Step 2.

Step 4: The dollar value calculated in Step 2 for each Load Zone, as adjusted by any allocation to Asset Related Demands and Dispatchable Asset Related Demands in Step 3, shall be distributed to each ARR Holder in the Load Zone. ~~The dollar value calculated in Step 2 for each External Node shall be distributed to each ARR Holder at the External Node. The ARR Holder(s) at an External Node is the Transmission Customer taking Long-Term Firm Through or Out Service for which the Point of Delivery is that External Node.~~ The distribution shall honor Excepted Transactions and NEMA Contracts, as appropriate.

The dollar values calculated in Step 3 for each Asset Related Demand and Dispatchable Asset Related Demand in a Load Zone (excluding station service and pumps) shall be distributed to the ARR Holders associated with the Asset Related Demand and Dispatchable Asset Related Demand.

The remainder of the ARR Holder's distribution shall be in proportion to~~: (i)~~ its Real-Time Load Obligation, excluding External Transaction sales, in the Load Zone at the time of the coincident peak for the New England Control Area for the month being settled less adjustments for Excepted Transactions and NEMA Contracts~~ and (ii) its Reserved Capacity at the Point of Delivery (an External Node) for any Long-Term Firm Through or Out Service for which the ARR Holder is the Transmission Customer~~. Since the four-stage ARR Allocation process is not inherently revenue neutral, a proportional adjustment is applied to the auction revenue awards to distribute all available FTR

Auction Revenues each month. The proportional adjustment is applied to ARRs awarded in the four-stage ARR Allocation process only.

III.C.7 Monthly ARR Settlement

ARR Holders shall receive a monthly share of FTR Auction Revenues ~~from FTRs sold in the monthly FTR Auctions. ARR Holders shall also receive~~ , reflecting a monthly share of ~~the FTR Auction Revenues from FTRs sold in the~~ annual ~~(~~FTR revenues and ~~long-term) FTR Auctions.~~ the revenues from all monthly FTRs effective for the month being settled. Such monthly share shall ~~recognize Qualified Upgrade Awards~~ reflect Incremental ARR awards, Excepted Transactions, NEMA Contracts, and the ARR Holder's Real-Time Load Obligation excluding External Transactions sales at the time of the coincident peak for the New England Control Area for the month being settled ~~and the ARR Holder's Reserved Capacity at the Point of Delivery (an External Node) for any Long-Term Firm Through or Out Service for which the ARR Holder is the Transmission Customer as described in Section III.C.6~~ as described in Section III.C.6. The Incremental ARR awards used in the settlement of FTR Auction Revenues shall be prorated in proportion to the amount of incremental network capacity made available in the FTR Auction resulting in the FTR Auction Revenues to be distributed in accordance with Section III.C.8.

III.C.8 ~~Qualified Upgrade~~Incremental ARR Awards

An entity who pays for transmission upgrades which increase transfer capability on the New England Transmission System, making it possible for the ISO to award additional FTRs in the FTR Auction, shall be awarded ~~Qualified Upgrade Awards. Such transmission upgrades initially placed in-service on or after March 1, 1997 may qualify for Qualified Upgrade Awards. The amount of the award to such an entity shall be consistent with the incremental revenues resulting from the FTRs awarded in an FTR Auction that were made possible by the transmission upgrade, respecting~~ Incremental ARRs. Transmission upgrades initially placed in-service on or after March 1, 1997 may qualify for Incremental ARR awards. The amount of any Incremental ARR award shall be specific MW quantities over one or more specific pairs of receipt and delivery points relevant to the upgrade and shall be determined once for each upgrade in accordance with Section III.C.8.1. The MW amount of the award shall reflect the amount of additional network capacity provided by the upgrade, prorated to reflect the entity's funding-share of the transmission system upgrade. An Incremental ARR award will have a value associated with each auction in which incremental network capacity is made available for the first time. The value will be determined by the sets of receipt and delivery points awarded for each Incremental ARR, the MW quantity awarded between each pair of receipt and delivery points, and the market-clearing prices for each pair of receipt and delivery points as determined by the auction. The determination of the sets of receipt and delivery points and the MW quantity associated with each pair, which comprise an Incremental ARR award, shall respect the order of service and study priority established through the Transmission, Markets and Services Tariff and ISO New England System Rules. Once determined, the subsequent valuation of an Incremental ARR depends only on the awarded set of receipt and delivery points and MW quantities, the amount of incremental network capacity made available in the FTR Auction, and on prices resulting from the associated FTR Auction. The Transmission, Markets and Services Tariff and ISO New England System Rules establish an order of both: (i) transmission upgrades eligible for ~~Qualified Upgrade~~ Incremental ARR ~~Awards~~awards; and (ii) transmission upgrades paid for through the Pool PTF Rate. To the extent that transmission upgrades resulting in new transfer capability are paid for through the Pool PTF Rate, any ARRs associated with the sale of FTRs made possible by such upgrades, other than FTRs sold by FTR Holders, shall be allocated to Transmission Customers and Congestion Paying LSEs in the four-stage ARR Allocation process.

An entity who pays for transmission upgrades, initially placed in-service on or after March 1, 2003, and who requests ~~Qualified Upgrade Awards~~ Incremental ARRs, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, will be responsible for the cost of any study required to determine such ~~Qualified Upgrade Awards~~Incremental ARRs.

~~Qualified Upgrade Awards shall continue for so long as the entity supports~~ Incremental ARRs shall be awarded to the entities funding the transmission upgrade at the later of the time the upgrade goes into service or when support payments begin, and shall continue for so long as the entities, or their successors, support the costs of the upgrade (either through up front support payments or periodic installments) or for the life of the upgrade (such as in the case where the upgrade is supplanted by a ~~prior~~ planned transmission system improvement published in the ISO's Regional System Plan prior to the upgrade's in-service date, but installed subsequently ~~installed, upgrade~~), if shorter.

~~By December 31, 2004, the ISO will develop a permanent process to replace the Qualified Upgrade Award process. The Qualified Upgrade Award process shall continue until the permanent process is implemented.~~

All previously granted awards specifically associated with transmission upgrades shall be converted to Incremental ARR awards.

At the time an Incremental ARR award is made, the funding entity must provide documentation to indicate the share of the total transmission upgrade cost the entity is supporting, and whether that share of the transmission upgrade total cost is either fully funded, or funded by ongoing support payments. If funded by ongoing support payments, the documentation must indicate the schedule of remaining support payments. The Incremental ARR Holder must provide, upon request of the ISO, documents confirming that ongoing support payments are being made as required. If adequate confirmation is not provided within 30 days of the ISO request, the associated Incremental ARR Award will be terminated.

Incremental ARR Holders shall not be entitled to receive a share of any excess Congestion Revenue in the Congestion Revenue Fund, nor shall they be required to make payments into the Congestion Revenue Fund when the fund is insufficient to pay positive target allocations to all FTR Holders, as described for ARR Holders in Sections III.5.2.5 and III.5.2.6 of Market Rule 1.

If in any month the monthly FTR Auction Revenues plus the monthly share of annual FTR Auction Revenue for the relevant month are insufficient to provide the full value of the Incremental ARRs, as described in this Section, to the Incremental ARR Holders, the value of all Incremental ARRs for the month shall be prorated in proportion to their full value, such that the prorated value of all Incremental ARRs for the month equals the available monthly FTR Auction Revenues.

Incremental ARRs may be transferred to a Market Participant that is eligible to receive Incremental ARR payments. A request to transfer Incremental ARRs must be submitted by the existing holder at least 30 days prior to the requested transfer date. If the transmission upgrade associated with the Incremental ARR is funded by an ongoing stream of support payments, the transfer request must be accompanied by documentation indicating that the transferee has assumed the obligation to make the continuing support payments.

III.C.8.1 Determination of Incremental ARRS

The ISO will determine a baseline Incremental ARR award to an entity for an eligible transmission system upgrade that will reflect the additional cleared FTR amounts between receipt and delivery points made possible by the upgrade. The baseline award will comprise one or more pairs of receipt and delivery points relevant to the upgrade in the prevailing direction of real-time electrical power flows at the time the determination is performed.

Relevant pairs of receipt and delivery points shall include the complete set of all direct paths (receipt point and delivery point are directly linked by the upgraded facility) and sequential direct paths (receipt and delivery points are linked by a series of contiguous upgraded facilities). Where the upgrade includes several non-contiguous facilities, the complete set of all direct paths may include a number of individual direct paths that cannot be combined into a single sequential direct path. Where the transmission system upgrade increases the transfer capability of a transmission interface, the Incremental ARR shall be determined using receipt and delivery points comprised of the pairs of receipt and delivery points that define the interface.

The Incremental ARR determination is performed assuming all lines in service with no equipment outages and no reductions in equipment or interface ratings. The amounts of the baseline award on the relevant pairs of receipt and delivery points shall be determined by: (1) measuring the maximum FTR that can be cleared using he FTR auction clearing software with the transmission system upgrade included in the modeled network; (2) measuring the maximum FTR that can be cleared in the same manner with the upgrade excluded; (3) calculating the difference in total cleared FTRs over each relevant pair of receipt and delivery points. The increase in cleared FTRs over the relevant pairs of receipt and delivery points becomes the baseline award.

After receiving the baseline award, the entity requesting the Incremental ARR award may request the ISO to provide up to three additional Incremental ARR determination analyses. The ISO shall provide the entity with a list of all qualifying pairs of receipt and delivery points relevant to the upgrade that may be considered. The entity shall then identify for each determination analysis a specific set of pairs selected from the list of qualifying pairs of receipt and delivery points. In each determination analysis, the entity may adjust the MW amounts and bids to be used in the clearing calculations over the qualifying pairs to reflect the entity's preferences and priorities for specific receipt and delivery point pairs in the Incremental ARR award. The ISO shall repeat the award determination analysis for the requested set of relevant pairs of receipt and delivery points, and shall provide the resulting MW awards to the entity. The entity shall then select the results of either the baseline award or any one of the determination analysis awards to become the final Incremental ARR award.

EXHIBIT 1

NEMA CONTRACTS

NEMA Load-Serving Entity	NEMA Contract Entitlements (Stated by percentages in the case of unit entitlement held on percentage basis, and by megawatts when contract states entitlement in megawatts.)
Danvers	1. Millstone 3 (0.263%) 2. Seabrook (1.112%) 3. Stony Brook Combined Cycle (8.457%) 4. Stony Brook 2A (11.555%) 5. Stony Brook 2B (11.555%) 6. Vermont Yankee (1.080 MW) 7. Hydro Quebec (2.930 MW (winter)) 8. NYPA (2.440 MW)
Georgetown	1. Millstone 3 (0.021%) 2. Seabrook (0.096%) 3. Stony Brook Combined Cycle (0.736%) 4. Stony Brook 2A (1.014%) 5. Stony Brook 2B (1.014%) 6. Vermont Yankee (0.144 MW) 7. System Power (Select Energy) (2.0 MW) 8. Hydro Quebec (0.280 MW (winter)) 9. NYPA (0.620 MW)
Ipswich	1. Millstone 3 (0.061%) 2. Seabrook (0.107%) 3. Stony Brook Combined Cycle (0.293%) 4. Vermont Yankee (0.522 MW) 5. NYPA (1.350 MW)

Marblehead	1. Millstone 3 (0.154%) 2. Seabrook (0.135%) 3. Stony Brook Combined Cycle (2.684%) 4. Stony Brook 2A (1.598%) 5. Stony Brook 2B (1.598%) 6. Wyman 4 (0.279%) 7. Vermont Yankee (0.655 MW) 8. Hydro Quebec (1.040 MW (winter)) 9. NYPA (2.140 MW)
Middleton	1. Millstone 3 (.044%) 2. Seabrook (0.328%) 3. Stony Brook Combined Cycle (0.878%) 4. Stony Brook 2A (1.892%) 5. Stony Brook 2B (1.892%) 6. Wyman 4 (0.101%) 7. Vermont Yankee (0.213%) 8. System Power (NU 10.000 MW, PGET 0.500 MW) 9. Hydro Quebec (0.580 MW (winter)) 10. NYPA (0.600 MW)
Peabody	1. Millstone 3 (0.297%) 2. Seabrook (1.130%) 3. Stony Brook Combined Cycle (13.052%) 4. Vermont Yankee (1.693 MW) 5. Hydro Quebec (3.480 MW (winter)) 6. NYPA (4.860 MW)
Reading	1. Millstone 3 (0.404%) 2. Seabrook (0.635%) 3. Stony Brook Combined Cycle (14.453%) 4. Stony Brook 2A (19.516%)

	5. Stony Brook 2B (19.516%) 6. System Power (NU) (15 MW) 7. Hydro Quebec (5.710 MW (winter))
Wakefield	1. Millstone 3 (0.206%) 2. Seabrook (0.387%) 3. Stony Brook (3.993%) 4. Stony Brook 2A (6.379%) 5. Stony Brook 2B (6.379%) 6. Wyman 4 (0.440%) 7. Vermont Yankee (0.885 MW) 8. Hydro Quebec (1.520 MW (winter)) 9. NYPA (2.230 MW)
Concord	1. Hydro Quebec (0.890 MW (winter))
Groveland	1. System Power (NU) (6.100 MW) 2. NYPA (0.510 MW)
Merrimac	1. System Power (NU) (4.900 MW) 2. NYPA (0.520 MW)
Rowley	1. System Power (NU) (6.700 MW) 2. Hydro Quebec (0.200 MW (winter)) 3. NYPA (0.510 MW)

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

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

I.2.2. Definitions:

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

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

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

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

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

ADR is alternative dispute resolution.

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

Affiliate, for purposes of Section I of the Tariff, is any person or entity which 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 and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Affiliate, for purposes of Section II of the Tariff, is, 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Average Hourly Output is either: (i) the sum of the Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; (ii) the sum of the Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month; (iii) the sum of a Critical Peak Demand Resource's electrical energy output during Demand Resource Critical Peak Hours in the month for that resource divided by the number of Demand Resource Critical Peak Hours for that resource less 30 minutes for each set of consecutive Real-Time

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

Backyard Generation is generation which interconnects directly with distribution facilities dedicated solely to load not designated as Network Load. Any distribution facilities which are shared with Network Load will not qualify.

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.

Billing Policy is defined in Exhibit ID to Section I of the Tariff.

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

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

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.3 of the Participants Agreement.

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

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

Capacity 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.

Capability Period means a period of time defined by the ISO for the purposes of rating and auditing resources. There are two Capability Periods, a Summer Capability Period and a Winter Capability Period. The dates defining the start and end of these periods are set forth in the ISO New England Manuals.

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

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

Capacity Carry-Forward Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.9 of Market Rule 1.

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

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

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

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

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

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5 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 of Market Rule 1.

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

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

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

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

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

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

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

Charge is defined in the ISO New England Billing Policy.

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

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

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

Commission is the Federal Energy Regulatory Commission.

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

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

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

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

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

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 or Long-Term Firm Point-to-Point Transmission 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.

Control Area, for purposes of Section II of the Tariff, is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:
(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Council; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

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

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

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

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

Critical Peak Hours, for purposes of determining ODR Performance Hours, is defined as (i) those hours in which the projected hourly load, as shown in the ISO's next day Forecast System Load as published daily on ISO's website, for hours ending 1400 through 1700, Monday through Friday on non-holidays, during the months of June, July, and August, and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast, as determined by the ISO, for the applicable summer or winter season, and (ii) hours when the ISO activates Action Steps 6 or higher of Operating Procedure Number 4 in the Load Zone where the ODR resource is located.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

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 Reduction Value is the quantity of reduced demand, measured at the end-use customer meter, produced by a Demand Resource, which is calculated pursuant to Section III.13.7.1.5 of Market Rule 1.

Demand Resource is a resource defined as On-Peak Demand Resources, Seasonal Peak Demand Resources, Critical Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Demand Resource Critical Peak Hours, Real-Time

Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

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

Demand Resource Forecast Peak Hours means those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Load Zone or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the relevant Operating Day. Beginning on June 1, 2011, **Demand Resource Forecast Peak Hours** are those hours, or portions thereof, in which, absent the dispatch of Critical Peak Demand Resources and Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours by 10:00 p.m. on the day before the next Operating Day.

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

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

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

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

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

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.

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.

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

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

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

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

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

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

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

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

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

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

Early Payment Shortfall Funding 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.

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

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

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

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.2 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

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

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

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

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

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

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

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

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

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

Emergency Service is the supply, from one neighboring control area operator to another, pursuant to the terms and conditions of applicable agreements for Emergency Energy, and any and all ancillary and transmission services associated with supplying such Emergency Energy.

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.

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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II of the Tariff.

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

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

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

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

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

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

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

EPSF Amount is defined in Section IV.B.2.4 of the Tariff.

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

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

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

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

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

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

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

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

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

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

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

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

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

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 a purchase by a Market Participant of energy external to the New England Control Area or a sale by a Market Participant of energy external to the New England Control Area in the Day-Ahead Energy Market and/or Real-Time Energy Market or a through transaction scheduled by a Non-Market Participant in the Real-Time Energy Market.

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

Failure-to-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.

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

FCA Cleared Export Transaction is defined in Section III.1.10(f)(ii) of Market Rule 1.

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

FCACPZone is defined in Section III.9.8(b) of Market Rule 1.

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

Filing Entity is a PTO or PTOs submitting a proposal to the FERC to participate in, join, or become an ITC in accordance with Attachment M of the OATT.

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

Financial Assurance Policy for Market Participants is defined in Exhibit IA to Section I of the Tariff.

Financial Assurance Policy for Non-Market Participant Transmission Customers is defined in Exhibit IB to Section I of the Tariff.

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 reserved and/or scheduled between specified Points of Receipt and Delivery in accordance with the applicable procedure specified in Part II.C of the OATT or the Local Service Schedule.

Firm Transmission Service is service for Native Load Customers, firm Regional Network Service, service for Excepted Transactions and certain other transactions listed in Attachment G3, Firm MTF Service, Firm OTF Service, and firm service provided under the Local Service Schedules.

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

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

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

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

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

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

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

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

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4 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.9.1.2 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 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 that is used to calculate the Forward Reserve Threshold Price.

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

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

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

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

Forward Reserve Procurement Period is defined in Section III.9.1.1 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.9.5.1 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.

FRACPZone is defined in Section III.9.8(b) 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 Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets, provided, however, that an FTR-Only Customer may also be a DRP-Only Customer and/or an ODR-Only Customer. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

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

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

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

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

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

Generator Maintenance Outage means the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the ISO New England Manuals and ISO New England Administrative Procedures.

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

Generator Planned Outage means the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the ISO in accordance with the ISO New England Manuals and ISO New England Administrative Procedures.

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 Participant is defined in the Participants Agreement.

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

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 or Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.5.8.3.

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

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

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 Objective Capabilities. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in Kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

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

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

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

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

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

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

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

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

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

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market. An accepted Increment Offer results in scheduled generation at the specified Location in the Day-Ahead Energy Market.

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

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

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 FERC and a finding of the FERC that the transmission entity satisfies applicable independence requirements.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Interruption is defined, for purposes of Schedule 21, as a reduction in non-firm transmission service due to economic reasons.

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.

ISO means ISO New England Inc.

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

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

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

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

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

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

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

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

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

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

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

ITC 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.

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

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

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

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

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

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

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

Load-shifting means the movement of load between Market Participants, where one Market Participant's Real-Time Load Obligation decreases as load leaves to obtain service from another Market Participant whose Real-Time Load Obligation increases.

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

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 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 Parties are, with respect to a PTO's Local Service Schedule, the PTO and the Transmission Customer receiving service under the such Local Service Schedule.

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 Network Upgrades are modifications or additions to the Local Network of a PTO, made in accordance with Schedule 21, that are not Direct Assignment Facilities.

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

Local Second Contingency Protection Resource is defined in Section III.6.1 of Market Rule 1.

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

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

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under the OATT associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

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

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

Long-Term: A term of one year or more.

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.

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

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

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

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

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

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

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

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

Firm Load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

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

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

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

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

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

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

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

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

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the MTOA, 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 that is a signatory to an MTOA with the ISO.

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

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

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

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

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

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

Mitigation Measures is defined in Section III.A.1.1 of Appendix A of Market Rule 1.

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

Monthly Network Load is defined in Section II.21.2.

Monthly Peak: is defined in Section II.21.2.

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.

MW is megawatt.

MWh is megawatt-hour.

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

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

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

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

NEMA 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.

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.

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.

NERC is the North American Electric Reliability Council.

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

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

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

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section

II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Network Load located in the New England Control Area or other designated 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 Network Load.

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

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

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

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

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

Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

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

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4 of Market Rule 1.

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

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

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

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

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

New England 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.

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

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

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

Non-Dispatchable Qualifying Facility means a qualifying small power production facility or a qualifying cogeneration facility as defined in Section 201 of PURPA and the regulations of the Federal Energy Regulatory Commission under PURPA that is also either: (a) a daily cycle hydro or wind generating unit that cannot be dispatched by the ISO; or (b) a Special Qualifying Facility, which is a Non-Dispatchable Qualifying Facility (other than a daily cycle hydro or wind generating unit) for which a Market Participant has a contractual arrangement or regulatory obligation such that the Market Participant buyer has no authority or ability to schedule the hourly energy from the unit.

Non-Firm Point-To-Point Service is Point-To-Point Service that is subject to Curtailment or interruption under the circumstances specified in Schedule 18, Section 3.1(e) of the OATT.

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

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

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

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

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

NPCC is the Northeast Power Coordinating Council.

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

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

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

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

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

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.

Operating Authority is defined pursuant to the MTOA or TOA 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 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).

Operating Reserve – Ten-Minute Non-Spinning Reserve Service (TMNSR) is the form of Ancillary Service described in Schedule 6.

Operating Reserve – Ten-Minute Spinning Reserve Service (TMSR) is the form of Ancillary Service described in Schedule 5.

Operating Reserve - Thirty-Minute Operating Reserve Service (TMOR) is the form of Ancillary Service described in Schedule 7.

Operations Date is February 1, 2005.

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

Other Demand Resource (ODR) is an installation undertaken as part of a merchant, utility, or state-sponsored program, and may include Energy Efficiency, Load Management, and Distributed Generation projects that are installed after June 16, 2006, and that result in additional and verifiable reductions in end-use customer demand on the electricity network in the New England Control Area during specified ODR performance hours of the ICAP Transition Period.

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

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

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

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

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

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.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Pivotal Supplier is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Point(s) of Delivery is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(s) of Receipt 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 is described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Pre-1997 PTF Rate is the transmission rate of a PTO determined in accordance with paragraph (5) of Schedule 9 to the OATT.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

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 Capacity Resource is a resource that has Qualified Capacity for a Capacity Commitment Period, or a portion thereof, that is not already obligated and that is seeking to acquire a Capacity Supply

Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Reactive Supply and Voltage Control From Qualified Reactive Resources Service is the form of Ancillary Service described in Schedule 2.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

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

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Load Zone or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours. Beginning on June 1, 2011, "Real-Time Demand Resource Dispatch Hours" shall be defined as those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Critical Peak Demand Resources and Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means the hours, or portions thereof, when the ISO dispatches Real-Time Demand Response Resources in the Load Zone where a Demand Resource is located in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours. Beginning on June 1, 2011, Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Demand Resource Forecast Peak Hours and Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report the output of one or more emergency generators as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources to curtail electric consumption. Real-Time Emergency Generation Resources would be dispatched by the ISO on a Load Zone or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. Beginning on June 1, 2011, Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose Federal, State and/or local air quality permits limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Accepted Electric Industry Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits is 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 Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Energy Obligation Credit is defined in Section III.10.5 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.8(b) of Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service 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.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3.

Regulation Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual M 11.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Replacement Reserve means reserve other than TMSR, TMNSR or TMOR as defined in the ISO New England Manuals.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

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.

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.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

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.

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.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year

2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Sanctions Rule is defined in Section III.B of the Tariff (Appendix B to Market Rule 1).

Schedule, Schedules, Schedule 1, 2 and 3 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider is defined in Schedule 20A to Section II of this 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.

Scheduling, System Control and Dispatch Service (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.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

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

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

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 Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment and that have elected Settlement Only Resource treatment as described in Section 5 of Attachment D to ISO New England Manual 20 – Installed Capacity.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.2.7.1.1.A.

Short-Term is a period of less than one year.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

SPD means the ISO's Scheduling, Pricing, and Dispatch software, as more fully described in Section III.A.5.5.3 of Appendix A of Market Rule 1.

Special Constraint Resources are Resources that provide Special Constraint Resource Service under Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

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

Start-Up Fee is the amount, in dollars, that must be paid for a generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the Net-Risk Adjusted Going Forward Costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

Submitted Offer is defined in Section III.A.5.6.1 of Appendix A of Market Rule 1.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Summer Capability Period is defined in the ISO New England Manuals.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Summer Season Demand Resource is a Demand Resource for which there is no or lower demand during winter peak associated with the end-use on which the Demand Resource measure is installed, and therefore the Winter Demand Reduction Value is zero or lower than the Summer Demand Reduction Value.

Supply Margin is defined in Section III.A.5.2.2 of Appendix A of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

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

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, or Schedule 23 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO , and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

Through or Out Service means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

Total Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Load Zone or, starting on June 1, 2011, in the same Dispatch Zone.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission 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 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 Forced Outage means an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the ISO New England Manuals and ISO New England Administrative Procedures. A removal from service of a transmission facility at the request of the ISO to improve transmission capability shall not constitute a Transmission Forced Outage.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

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 Planned Outage means any transmission outage scheduled in advance for a predetermined duration and which meets the notification requirements for such outages specified in the ISO New England Manuals and ISO New England Administrative Procedures.

Transmission Provider is defined in Section II of the Transmission, Markets and Services Tariff.

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 Section II of the Tariff, entered into by the Transmission Customer and the ISO for Regional Network Service, Through or Out Service or MTF Service; (B) entered into by the Transmission Customer with the PTO in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service; or (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of Section II of this Tariff. A Transmission Service Agreement shall be required for MTF Service and OTF Service, and shall be required for all other types of transmission service if the Transmission Customer is not executing an MPSA because it is not participating in the ISO New England Market.

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

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

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

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated

Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.6 of Market Rule 1 and the ISO New England Manuals.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. The time period associated with the Winter Capability Period is defined in the ISO New England Manuals.

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.2.7of Market Rule 1.

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Eligible Customer elects not to execute a System Impact Study agreement, its Application shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) shall be returned with Interest

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II.19.2 System Impact Study Agreement and Cost Reimbursement:

(a) The System Impact Study agreement, whether in the form detailed in Attachment I or in any other form that is mutually agreed to, will clearly specify the ISO's actual estimate of the actual cost, and time for completion of the System Impact Study. The actual charge shall not exceed the actual cost of the study. The System Impact Study shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF.

(b) If in response to multiple Eligible Customers requesting the service in relation to the same competitive solicitation, a single System Impact Study to accommodate the service, the costs of that study shall be prorated among the Eligible Customers.

(c) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owners on whose behalf the System Impact Study is conducted will record the cost of the System Impact Studies pursuant to Section II.8.5 of this OATT.

II.19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners and indirectly affected MTOs or OTOs will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study, if required, shall identify any system constraints, or the need for additional Direct Assignment Facilities or other facility additions or upgrades to provide the requested service. In the event that the ISO and the PTO designated to perform the study are unable to complete the required System Impact Study within such time period, the ISO shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due

diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for the Transmission Owners. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the New England Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen
(15) days of completion of the System Impact Study the Eligible Customer must execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s), or the Application shall be deemed terminated and withdrawn.

II.19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the PTF are needed to supply the Eligible Customer's service or to mitigate indirect impacts on the MTF or OTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a Facilities Study agreement, its Application shall be deemed withdrawn and its deposit, if any (less the reasonable Administrative Costs incurred by the ISO and any affected entities), shall be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s), will use due diligence to complete the required Facilities Study within a sixty-day period. If the ISO and any affected PTO(s) are unable to complete the Facilities Study in the allotted time period, the ISO shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Transmission Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected PTO(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Transmission Service

Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s) and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn. In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

II.19.5 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO’s notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.19.6 Clustering of Regional Network Service Studies:

(a) Cluster Studies Request: The ISO, on its own initiative, or at the request of a group of Eligible Customers may consider studying specified requests for Regional Network Service in a cluster for the purpose of the System Impact Study and Facilities Study.

(b) Notice of Study Cluster: At the same time that the ISO informs the Eligible Customers that a System Impact Study or a Facilities Study is necessary to accommodate the requested Regional Network Service in accordance with Sections II.19.1 and II.19.4 of this OATT, the ISO will also notify the Eligible Customers, either in response to their joint request or on its own initiative that (i) studying specific multiple requests for Regional Network Service in a cluster may result in a more efficient study process or may result in a more efficient and economic construction of the new facilities or upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study, as specified in Sections II.19.3 and II.19.4 of this OATT. If an Eligible Customer chooses not to have its Regional Network Request studied as part of the cluster, it shall have ten (10) days from the date that the ISO notifies the Eligible Customer of its intent to study specific multiple requests for Regional Network Service in a cluster to inform the ISO of its determination to have its request studied separately.

(c) Cluster Study Process and Procedures: The ISO shall follow the process and procedures set forth in Sections II.19.1 through II.19.4 of this OATT with respect to the performance of the System Impact Study and the Facilities Study, except that:

(i) For clustered studies, a single study agreement either in the form detailed in Attachment I or Attachment J of this OATT, as applicable, or in any other form that is mutually agreed to, will be tendered by the ISO to all Eligible Customers, which is to be entered into by all the Eligible Customers and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s), and pursuant to which the Eligible Customers shall agree to reimburse the ISO and affected PTO(s) for performing the required study. The costs of that study will be divided equally among the Eligible Customers, unless otherwise agreed to by the ISO and the Eligible Customers.

(ii) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the date on which all Eligible Customers in the cluster have executed the applicable study agreement. If the ISO and any affected PTO(s) are unable to complete the applicable study in the allotted time period, the ISO shall notify the Eligible Customers and provide an estimate of the time needed to complete the study and an explanation of the reasons that additional time is required to complete the study.

(iii) In the event that ISO determines that additions or upgrades to the PTF are required to accommodate the requests for Regional Network Service that are studied as part of a cluster, the costs of the Transmission Upgrades will be allocated to each Eligible Customer whose request was studied as part of the cluster based on each Eligible Customer's share of the total megawatts of service requested, unless otherwise agreed to by the ISO and the Eligible Customers.

(iv) At the request of a Transmission Customer whose Regional Network Service request was studied as part of a cluster, the ISO shall provide a non-binding estimate of the Incremental ARRs, if any, resulting from the construction of new facilities based on the Transmission Customer's share of the costs of the new facilities. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

II.31 Service Availability

II.31.1 General Conditions: Through or Out Service on the PTF shall be available to any Transmission Customer that has met the applicable requirements of Section II.32.

II.31.2 Determination of Available Transfer Capability: A description of the ISO's specific methodology for assessing available transfer capability posted on the OASIS (Section II.5 of this OATT) is contained in Attachment C of this OATT.

II.31.3 Initiating Service in the Absence of an Executed Transmission Service Agreement: If the ISO and the Transmission Customer requesting Point-To-Point Service, who has not executed an MPSA or on whose behalf the ISO has not filed an unexecuted MPSA with the Commission, cannot agree on all the terms and conditions of the applicable Transmission Service Agreement, the ISO will file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the ISO to file, an unexecuted Transmission Service Agreement containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO) for such requested transmission service. The service will be commenced subject to the Transmission Customer agreeing to (i) pay whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this OATT including providing appropriate security deposits in accordance with the terms of Section II.34.3.

II.31.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the New England Transmission System: If a Transmission Customer requests that the PTF be expanded or modified, one or more PTOs or other entities will be designated to use due diligence to expand or modify the PTF to increase transfer capability, provided that the Transmission Customer agrees to compensate the PTO(s) or other entities that will be responsible for the construction of any new facilities or upgrades for the costs of such new facilities or upgrades pursuant to the terms of Section II.38. The ISO and the designated PTOs or other entities will conform to Good Utility Practice and the planning obligations in Attachment K in determining the need for new transmission facilities or upgrades and in coordinating the design and construction of such facilities. This obligation applies only to those facilities that the designated PTO(s) or other entities have the right to expand or modify.

II.31.5 Deferral of Service: Any Incremental ARR associated with new transmission facilities or upgrades shall be subject to completion of construction of those transmission facilities and upgrades and to such upgrades being placed in service.

II.31.6 Real Power Losses: Real power losses are associated with all transmission service. The ISO, Transmission Owners and Schedule 20A Service Providers are not obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices pursuant to Market Rule 1. Real power losses across MTF shall be allocated in accordance with Schedule 18 of this OATT and real power losses across OTF shall be allocated in accordance with Schedule 20 of this OATT.

II.31.7 Load Shedding: To the extent that a system contingency exists on the PTF, MTF or OTF and the ISO determines that it is necessary for the Transmission Owners and the Transmission Customers to shed load, the Parties shall shed load in accordance with the ISO System Rules or in accordance with other mutually agreed-to provisions.

II.34 Study Procedures For Through or Out Service Requests

II.34.1 Notice of Need for System Impact Study: A request for Through or Out Service will not normally require a System Impact Study. An Eligible Customer may specifically request that the ISO conduct a System Impact Study for an Elective Transmission Upgrade pursuant to Section II.47.2 of this OATT (a "Study Request"). After receiving a request to study an Elective Transmission Upgrade, the ISO will review the effect of the proposed service or upgrade on the reliability requirements to meet existing and pending obligations of the Transmission Customers, and the obligations of any affected Transmission Owner(s) whose facilities will be impacted by the proposed service and determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D. After receiving a Request, the ISO will within thirty (30) days of receipt of a Study Request, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owners for performing or participating in the required System Impact Study. Before a Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact Study agreement, its request shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) in connection with the Application), will be returned with Interest.

II.34.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study agreement shall clearly specify the ISO's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF and indirectly affected MTF or OTF of the customer request for an Elective Transmission Upgrade.

(ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.

(iii) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owner will record the cost of the System Impact Studies pursuant to Section II.8.5 to this OATT.

II.34.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study shall identify the need for additional Direct Assignment Facilities or facility additions or upgrades required to comply with the Eligible Customer's request. In the event that the required System Impact Study cannot be completed within such time period, the ISO will so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required study and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer that is not a Market Participant as it uses when completing studies for an Eligible Customer that is a Market Participant. The ISO will notify the Eligible Customer immediately upon completion of the System Impact Study.

II.34.4 Facilities Study Procedures: After a System Impact Study indicates that additions or upgrades to the PTF or indirectly affected MTF or OTF are needed to accommodate the Eligible Customer's Study Request, the ISO, within thirty (30) days of the completion of the System Impact Study, will tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) or other entity designated by the ISO for performing any required Facilities Study. If the Eligible Customer wants the ISO to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study agreement, its Study Request shall be deemed withdrawn and its deposit, if any (less the reasonable administrative costs incurred by the ISO and any affected entity in connection with the Application), will be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s) or other designated entity will use due diligence to cause the required Facilities Study to be completed within a sixty-day period. If a Facilities Study cannot be completed in the allotted time period, the ISO will notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, or (ii) the Eligible Customer's appropriate share of the cost of any required upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Owner(s)or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of the new facilities or upgrades and consistent with relevant commercial practices, as established by the Uniform Commercial Code.

In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

II.34.5 Facilities Study Modifications: Any change in design arising from inability to site or construct proposed facilities will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the affected Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades and that significantly affect the final cost of the new facilities or upgrades to be charged to the Eligible Customer pursuant to the provisions of this OATT.

II.34.6 Due Diligence in Completing New Facilities: The ISO will use due diligence to designate PTOs or other entities to add necessary facilities or upgrade the PTF, MTF or OTF within a reasonable time. A

PTO or other entity will have no obligation to upgrade its existing or planned transmission system if doing so would impair system reliability or otherwise impair or degrade existing firm service. Nothing in this OATT shall be deemed to create an obligation to build upgrades that an entity does not otherwise have by contract, law or regulation.

II.34.7 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO to tender at one time, together with the results of required studies, an "Expedited Study Request" pursuant to which the Eligible Customer would agree to pay for all costs incurred pursuant to the terms of this OATT. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Study Request covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying the need for facility additions or upgrades and costs to be incurred in providing the requested service. While the ISO, on behalf of the PTO(s) or other entities that will be responsible for constructing the new facilities or upgrades, agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer shall agree in writing to pay for all costs incurred pursuant to the provisions of this OATT. The Eligible Customer shall execute and return such an Expedited Study Request within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

II.34.8 Penalties for Failure to Meet Study Deadlines: Sections 34.3 and 34.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.43 Auction Revenue Rights and Incremental ARRs:

A system of Auction Revenue Rights and Incremental ARRs shall be implemented pursuant to Appendix C of Market Rule 1.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

(a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Point-To-Point Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.

(b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade.

Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22 and 23 to this OATT.

(c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade may be required or proposed pursuant to a Regional System Plan. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or NEMA Upgrade is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with Schedule 12 of this OATT.

(d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission Owners and the operators of the affected Local Control Centers with such information as is necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive.
Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated Incremental ARRs equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 11 or 12 to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

SCHEDULE 21 - LOCAL SERVICE

This Schedule 21 contains the main substantive provisions applicable to Local Service. It includes common PTO rates, terms and conditions for Local Point-to-Point Service and Local Network Service and PTO-specific Local Service Schedules. Retail service is not subject to this Schedule 21 unless specifically provided for in the PTO's Local Service Schedule. The rates, terms and conditions for interconnection service to generators with total generating capacity of greater than 20 MW are set forth in Schedule 22. The rates, terms and conditions for interconnection service to generators with total generating capacity of 20 MW and less are set forth in Schedule 23. To the extent applicable, the rates, terms and conditions for load interconnections are set forth under the PTO-specific Local Service Schedules.

All Transmission Customers taking Local Service shall be subject to and comply with the rates, terms and conditions of this Schedule 21 as well as any applicable Local Service Schedule. In the event of a conflict between any rate, term or condition in the Tariff and any rate, term or condition in this Schedule 21 and/or an applicable Local Service Schedule, the rate, term or condition in this Schedule 21 and/or the applicable Local Service Schedule shall govern.

With the exception of waivers specified in certain PTO-specific Local Service Schedules, the following NAESB Standards are hereby incorporated by reference in this Schedule 21 to the extent that the requirements therein apply to the PTOs:

Business Practice Standards relating to Open Access Same-Time Information Systems (OASIS), Version 1.5 (WEQ-001, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009) with the exception of Standards 001-0.1, 001-0.9 through 001-0.13, 001-1.0, 001-9.7, 001-14.1.3, and 001-15.1.2;

Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.5 (WEQ-002, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009;

Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.5 (WEQ-003, Version 002.1, March 11, 2009, with minor corrections applied on May 29, 2009 and September 8, 2009);

Public Key Infrastructure (PKI) (WEQ-012, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.5 (WEQ-013, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009).

The Participating Transmission Owners have been granted a waiver of the following NAESB Version 002.1 Standards by Order of the Commission dated December 3, 2010 in FERC Docket No. ER11-23-000.

Coordinate Interchange (WEQ-004, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Area Control Error (ACE) Equation Special Cases (WEQ-005, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Manual Time Error Correction (WEQ-006, Version 001, October 31, 2007, with minor corrections applied on November 16, 2007);

Inadvertent Interchange Payback (WEQ-007, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009);

Transmission Loading Relief - Eastern Interconnection (WEQ-008, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009); and

Gas/Electric Coordination (WEQ-011, Version 002.1, March 11, 2009, with minor corrections applied May 29, 2009 and September 8, 2009). *To the extent that this standard does apply to an individual PTO, the incorporation of this standard shall be addressed within the respective PTO-specific Local Service Schedule.*

The PTOs will perform their functions under this Schedule 21 and the Local Service Schedules in a manner that is not inconsistent with the ISO's provision of regional service, administration of the regional markets, dispatch of resources, and operation of the New England Transmission System for purposes of reliability.

Pre-Confirmed Request: Is an OASIS transmission service request that commits the Transmission Customer to take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Point-to-Point Service.

Pre-RTO Local Service Agreements [1]: A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Firm or Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that was in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement" as defined to Section II.1 of the OATT) shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Pre-RTO Local Service Agreement.

A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Pre-RTO Local Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing pre-RTO Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

RTO Local Service Agreements: For Local Service Agreements with an effective date on or after February 1, 2005 (an "RTO Local Service Agreement" as defined to Section II.1 of the OATT) a Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of its existing Local Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the Transmission Customer's existing Local Service Agreement may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement. A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its

[1] LSAs as defined in Section II.1 of the OATT do not include Excepted Transaction Agreements under Attachments G-1, G-2 and G-3 of the OATT.

existing RTO Local Service Agreement, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing RTO Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission only, with a contract term of five years or more), have the right to continue to take Local Service from the PTO when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the PTO or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the PTO's Local Network cannot accommodate all of the requests for Local Service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the PTO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its Local Service Agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Local Service Agreements subject to a right of first refusal entered into prior to the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890 or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890; provided that, the one year notice requirement shall apply to such service agreements with five years or more left in their terms as of the date of the PTOs' filing adopting the reformed rollover language herein in compliance with Order No. 890.

Force Majeure: Neither the ISO, a Transmission Owner nor a Customer will be considered in default as to any obligation under the Tariff 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 or under a Service Agreement. However, an entity whose performance under the Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under the Tariff, and shall promptly notify the ISO, the

Transmission Owner or the Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

Liability: The ISO shall not be liable for money damages or other compensation to the Customer for actions or omissions by the ISO in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by the ISO is found to result from its gross negligence or willful misconduct. A Transmission Owner shall not be liable for money damages or other compensation to the Customer for action or omissions by such Transmission Owner in performing its obligations under the Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from it gross negligence or willful misconduct. To the extent the Customer has claims against the ISO or a Transmission Owner, the Customer may only look to the assets of the ISO or a 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 the ISO or a Transmission Owner or Affiliate of either who, the Customer acknowledges and agrees, have no personal or other liability for obligations of the ISO or a Transmission Owner by reason of their status as directors, members, shareholders, officers, employees or agents of the ISO or a Transmission Owner or Affiliate of either. In no event shall the ISO, a Transmission Owner or any 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 the Tariff or any Service Agreement thereunder. Notwithstanding the foregoing, nothing in this section shall diminish a Customer's obligations under Section I.5.3 of the Tariff or under Schedule 21 of the OATT.

Indemnification: Each Customer shall at all times indemnify, defend, and save harmless the ISO and the Transmission Owners and their respective directors, officers, members, employees and agents from any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO or Transmission Owners under the Tariff or any Service Agreement thereunder, any bankruptcy filings made by a Customer, or the actions or omissions of the Customer in connection with the Tariff or any Service Agreement thereunder, except in case of the ISO, gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents, and, in the case of a Transmission Owner, the gross negligence or willful misconduct by such 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 each Customer to indemnify the ISO and Transmission Owners shall be several, and not joint or joint and several.

I. LOCAL POINT-TO-POINT SERVICE

Preamble

Eligible Customers seeking Local Point-To-Point Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Firm and Non-Firm Local Point-To-Point Service will be provided pursuant to the rates, terms and conditions set forth below. Local Point-To-Point Service is for the receipt of capacity and/or energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

A Local Point-To-Point Service Customer 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 PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

1) Nature of Firm Local Point-To-Point Service

a) Term: The minimum term of Firm Local Point-To-Point Service shall be one day and the maximum term shall be specified in the Local Service Agreement.

b) Reservation Priority: Local Long-Term Firm Point-To-Point Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Local Short-Term Firm Point-To-Point Service will be conditional based upon the length of the requested transaction. However, Pre-Confirmed Requests for Local Short-Term Point-to-Point Service will receive priority over earlier-submitted requests that are not pre-confirmed and that have equal or shorter duration. Among requests with the same duration and, as relevant, pre-confirmation status (pre-confirmed or not pre-confirmed), priority will be given to a Transmission Customer's request that offers the highest price, followed by the date and time of the request. If the Local Network becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, a Transmission Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Local Short-Term Firm Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.1.h of this Schedule 21) from being notified by the PTO of a longer-term competing request for Local Short-Term Firm Point-To-Point Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration requests shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of this Schedule 21. Firm Local Point-To-Point Service will always have a reservation priority over Non-Firm Local Point-To-Point Service under the Tariff. All Local Long-Term Firm Point-To-Point Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in the Local Service Schedules of this Schedule 21.

c) **Use of Firm Local Point-to-Point Service by the PTO**: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of the Local Point-To-Point Service to make Third-Party Sales.

d) **Service Agreements**: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Transmission Customer Obligations for Facility Additions Costs: In cases where the PTO, in consultation with the ISO, determines that the Local Network is not capable of providing Firm Local Point-To-Point Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Local Point-To-Point Service, or (2) interfering with the PTO's ability to meet prior firm contractual commitments to others, the PTO will be obligated to expand or upgrade its Local Network pursuant to the terms of Section I.3.d of this Schedule 21. The Transmission Customer must agree to compensate the PTO for any necessary transmission facility additions pursuant to the terms of Section I.14 of this Schedule 21. Any Local Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Local Service Agreement prior to initiating service.

f) Curtailment of Firm Local Point-To-Point Service: In the event that a Curtailment on the PTO's Local Network, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the PTO will curtail service to Network Customers and Transmission Customers taking Firm Local Point-To-Point Service on a basis comparable to the curtailment of service to the PTO's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Point-To-Point Service and Local Network Service. When the PTO determines that an electrical emergency exists on the Non-PTF and the PTO implements emergency procedures to Curtail Firm Local Service, the Transmission Customer shall make the required reductions upon request of the PTO. The PTO reserves the right to Curtail, in whole or in part, any Local Service when, in the PTO's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Local Network. The PTO will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. Penalties for failure to Curtail shall be assessed pursuant to the applicable Local Service Schedule.

g) Classification of Firm Local Point-To-Point Service:

(i) The Transmission Customer taking Firm Local Point-To-Point Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section I.10.a of this Schedule 21 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section I.10.b of this Schedule 21.

(ii) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the PTO's Local Network. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(iii) The PTO shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. For Long-Term Firm Point-To-Point Service, each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Local Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. For Short-Term Firm Point-To-Point Service, Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties. For Long-Term Firm Point-To-Point Service, each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. For Short-Term Firm Point-To-Point Service, Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of the applicable Local Service Schedule. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in the applicable Local Service Schedule. The Local Service Schedule shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved.

h) Scheduling of Firm Local Point-To-Point Service: Schedules for the Transmission Customer's Firm Local Point-To-Point Service must be submitted to the PTO no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their service requests at a common point of receipt into units of 10 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO, and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

2) Nature of Non-Firm Local Point-To-Point Service

a) Term: Non-Firm Local Point-To-Point Service will be available for periods ranging from one (1) hour to one (1) month. However, a purchaser of Non-Firm Local Point-To-Point Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section I.6.c of this Schedule 21.

b) Reservation Priority: Non-Firm Local Point-To-Point Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers, Excepted Transactions and other Transmission Customers taking Local Long-Term and Local Short-Term Firm Point-To-Point Service. Individual Local Service Schedules may contain other applicable services. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Requests. In the event the Local Network is constrained, competing requests of the same pre-confirmation status and equal duration will be prioritized based on the highest price offered by the Transmission Customer for the Transmission Service, or in the event the price for all Transmission Customers is the same, will be prioritized on a first-come, first-served basis, i.e., in the chronological sequence in which each customer has requested service. Transmission Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Local Point-To-Point Service will be granted if the Transmission Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Local Point-To-Point Service after notification by the PTO; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section I.2.f of this Schedule 21) for Non-Firm Local Point-To-Point Service other than hourly transactions after notification by the PTO. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the OATT.

c) Use of Non-Firm Local Point-To-Point Service by the PTO: The PTO will be subject to the rates, terms and conditions of this Schedule 21 when making Third-Party Sales under (i) agreements executed on or after the effective date of the Tariff. The PTO will maintain separate accounting for any use of Non-Firm Local Point-To-Point Service to make Third-Party Sales.

d) Service Agreements: After consultation with the PTO, the ISO shall forward a standard form of Local Service Agreement (Attachment A to this Schedule 21) to an Eligible Customer after an Eligible Customer submits a Completed Application for Local Point-To-Point Service to the ISO. Local Service Agreements executed by the Eligible Customer that contain the information required under this Schedule 21 shall also be executed by the PTO and returned to the ISO for execution and filing and/or reporting by the ISO with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Local Point-to-Point Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Local Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Local Service Agreement.

e) Classification of Non-Firm Local Point-To-Point Service: The PTO and the ISO undertake no obligation under the Tariff to plan the Local Network in order to have sufficient capacity for Non-Firm Local Point-To-Point Service. Parties requesting Non-Firm Local Point-To-Point Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the PTO) exceeds its non-firm capacity reservation. Non-Firm Local Point-To-Point Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.

f) Scheduling of Non-Firm Local Point-To-Point Service: Schedules for Non-Firm Local Point-To-Point Service must be submitted to the PTO no later than 2:00 p.m. of the day prior to commencement of such service. Schedules submitted after these times will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 10 kW per hour. Transmission Customers within the PTO's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 10 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 10 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The PTO will furnish hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the PTO and the PTO shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

g) Curtailment or Interruption of Service: The PTO reserves the right to Curtail, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Local Network. The PTO reserves the right to Interrupt, in whole or in part, Non-Firm Local Point-To-Point Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Local Transmission Service, (2) a request for Non-Firm Local Point-To-Point Service of greater duration, (3) a request for Non-Firm Local Point-To-Point Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The PTO also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Local Point-To-Point Service shall be subordinate to Firm Local Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Local Point-To-Point Service under the Tariff. Non-Firm Local Point-To-Point Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Local Point-To-Point Service under the Tariff. The PTO will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice and in accordance with the applicable Local Service Schedule. Penalties for failure to Curtail or Interrupt shall be assessed pursuant to the applicable Local Service Schedule.

3) Service Availability

a) General Conditions: The PTO will provide Firm Local and Non-Firm Local Point-To-Point Service to any Transmission Customer that has met the requirements of Section I.4 of this Schedule 21.

b) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

c) Initiating Service in the Absence of an Executed Service Agreement: If the PTO and the Transmission Customer requesting Firm Local or Non-Firm Local Point-To-Point Service cannot agree on all of the terms and conditions of the Local Service Agreement, the ISO shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification to both the PTO and the ISO directing the ISO to file, an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service. The PTO shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the PTO at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section I.5.c of this Schedule 21.

d) Obligation to Provide Transmission Service that Requires Expansion or Modification of the Local Network: If the PTO, in consultation with the ISO, determines that a Completed Application for Firm Local Point-To-Point Service cannot be accommodated because of insufficient capability on the Local Network, the PTO will use due diligence to expand or modify its Local Network to provide the requested Firm Local Point-To-Point Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the PTO for such costs. The PTO, in consultation with the ISO, will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation of the PTO to expand or modify its Local Network obligation to provide the requested Firm Local Point-To-Point Service applies only to those facilities that the PTO has the right to expand or modify.

e) **Deferral of Service**: The PTO may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Local Point-To-Point Service whenever the PTO determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

f) **Other Transmission Service Schedules**: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

g) **Real Power Losses**: Real Power Losses are associated with all transmission service. Neither the ISO nor the PTOs are obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

h) **Load Shedding**: Load Shedding shall occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

4) **Transmission Customer Responsibilities**

a) **Conditions Required of Transmission Customers**: Firm Local and Non-Firm Local Point-To-Point Service shall be provided only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service;

(ii) The Transmission Customer meets the creditworthiness procedures in Attachment L to the applicable PTO's Local Service Schedule;

(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the PTO prior to the time service commences;

(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer, whether or not the Transmission Customer takes service for the full term of its reservation;

(v) The Transmission Customer provides the information required by the PTO's planning process established in Attachment K; and

(vi) The Transmission Customer has executed a Local Service Agreement or has requested the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21.

b) Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Eligible Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO and the PTO, notification to the ISO and the PTO identifying such systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this Schedule 21 on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the ISO and the PTO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

5) Procedures for Arranging Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of its existing Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement may be required. Instead, the Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify its existing Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of its existing Firm Local Point-to-Point Service Agreement, shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, or make upgrades (i.e., increase MWs served) within the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) Transmission Customers who wish to request an alternate Firm Point of Receipt or Point of Delivery or make upgrades (i.e., increase MWs served) beyond the terms of the existing Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) an Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: A request for Firm Local Point-To-Point Service for periods of one year or longer must be made in a completed Application submitted to the ISO at least sixty (60) days in advance of the calendar month in which service is to commence. The PTO will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the PTO and the Eligible Customer within the time constraints provided in the applicable Local Service Schedule. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The ISO and the PTO will treat this information as confidential except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to the Information Policy;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTO's Local Network; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Service upon acceptance on OASIS by the PTO that can provide the requested Local Service; and

(x) Any additional information required by the PTO’s planning process established in Attachment K.

The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) **Deposit**: Except as is otherwise provided in the Local Service Schedule, a Completed Application for Firm Local Point-To-Point Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected because it does not meet the conditions for service as set forth herein, in the Local Service Schedule or, in the case of requests for service arising in connection with losing bidders, in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the PTO in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the PTO if the PTO is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Local Service Agreement for Firm Local Point-To-Point Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the PTO to the extent such costs have not already been recovered by the PTO from the Eligible Customer. The PTO will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section I.5.c of this Schedule 21. If a Local Service Agreement for Firm Local Point-To-Point Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Local Service Agreement. Applicable interest shall be computed in accordance with the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the PTO's account.

f) **Notice of Deficient Application**: If an Application fails to meet the requirements of the Tariff, the PTO shall notify the ISO within ten (10) days of the Application’s receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. The PTO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application. The PTO shall return any deposit, with interest, to the Eligible Customer. Upon receipt of a new or revised Application that fully complies with the requirements of this Schedule 21, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

g) Response to a Completed Application: Following receipt of a Completed Application for Firm Local Point-To-Point Service, the PTO shall make a determination of available transfer capability as required in Section I.3.b of this Schedule 21. Within twenty-five (25) days after the date of receipt of a Completed Application, the PTO shall notify the ISO either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application. The ISO shall so notify the Eligible Customer within five (5) days of the ISO's receipt of such notice from the PTO. Responses by the PTO and the ISO must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

h) Execution of Service Agreement: Whenever the PTO, in consultation with the ISO, determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section I.7 of this Schedule 21 will govern the execution of a Local Service Agreement. Failure of an Eligible Customer to execute and return the Local Service Agreement or request the filing of an unexecuted service agreement pursuant to Section I.3.c of this Schedule 21 within fifteen (15) days after the Local Service Agreement is tendered will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

i) Extensions for Commencement of Service: The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying to the PTO a non-refundable annual reservation fee equal to one-month's charge for Firm Local Point-To-Point Service for each year or fraction thereof within 15 days of notifying the PTO it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Local Point-To-Point Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

6) Procedures for Arranging Non-Firm Local Point-To-Point Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall not be required to complete an Application or execute a Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement may be required. The Transmission Customer shall contact the associated PTO to discuss and, if appropriate, modify the existing Non-Firm Local Point-to-Point Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Non-Firm Local Point-to-Point Service Agreement that is in effect prior February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Non-Firm Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall not be required to execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21 may be required.

Such modifications to an existing Local Service Agreement typically do not require an additional local or regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21.

(ii) A Transmission Customer who wishes to request an upgrade (i.e., increase MWs served) beyond the terms of the existing Non-Firm Local Point-to-Point Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application: Eligible Customers seeking Non-Firm Local Point-To-Point Service must submit a Completed Application to the ISO. A Completed Application may be submitted by transmitting the required information to the ISO by telefax. This method will provide a time-stamped record for establishing the service priority of the Application.

d) Completed Application: A Completed Application shall provide all of the information included in 18 C.F.R. § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the ISO and the PTO also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service;

(vii) The electrical location of the ultimate load; and

(viii) A statement indicating that if the Transmission Customer submits a Pre-Confirmed Request, then the Transmission Customer will take and pay for the requested Local Point-to-Point Service upon acceptance on OASIS by the PTO that can provide the requested Local Service.

The ISO and the PTO will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to the ISO New England Information Policy. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

e) Reservation of Non-Firm Local Point-To-Point Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable.

f) Determination of Available Transfer Capability: The PTO shall determine available transfer capability in accordance with its respective Attachment setting forth its Methodology to Assess Available Transfer Capability.

7) Additional Study Procedures For Firm Local Point-To-Point Service Requests

a) Notice of Need for System Impact Study: After receiving a request for Firm Local Point-To-Point Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedules.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same geographical or electrically interconnected area requesting that a System Impact Study for Local Service be clustered, the PTO will cluster such multiple requests if it can reasonably do so. The costs of that study shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers.

(v) Once a clustered study is initiated by the PTO, as evidenced by an executed System Impact Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in Section 7(b)(iv) above, unless otherwise agreed to by the parties to such System Impact Study Agreement.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints identified with specificity by a transmission element or flowgate, and additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section I.3.c of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the

Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on facilities other than Non-PTF, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be divided equally among the Eligible Customers, unless otherwise agreed to by the PTO and the Eligible Customers. Once a clustered study is initiated by the PTO, as evidenced by an executed Facilities Study Agreement, Eligible Customers opting out of a clustered study regarding Non-PTF facilities shall be liable for their share of the study costs as set forth in this Section 7(d) above, unless otherwise agreed to by the parties to such Facilities Study Agreement. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit, pursuant to Section I.5.c of this Schedule 21, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Transmission Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

e) **Facilities Study Modifications**: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the

PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) Due Diligence in Completing New Facilities: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Firm Local Point-To-Point Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) Partial Interim Service: If the PTO determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Local Point-To-Point Service, the PTO nonetheless shall be obligated to offer and provide the portion of the requested Firm Local Point-To-Point Service that can be accommodated without addition of any facilities. However, the PTO shall not be obligated to provide the incremental amount of requested Firm Local Point-To-Point Service that requires the addition of facilities or upgrades to the Local Network until such facilities or upgrades have been placed in service.

h) Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO (in consultation with the PTO) to tender at one time, together with the results of required studies, an "Expedited Local Service Agreement" pursuant to which the Eligible Customer would agree to compensate the PTO for all costs incurred. In order to exercise this option, the Eligible Customer shall request in writing an expedited Local Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the PTO agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the PTO for all costs incurred. The Eligible Customer shall execute and return such an Expedited Local Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

i) Penalties for Failure to Meet Study Deadlines: Sections I.7.c and I.7.d of this Schedule 21 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The PTO is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the PTO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the PTO shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The PTO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The PTO is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the PTO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the PTO completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the PTO takes to complete that study beyond the 60-day deadline.

j) **Claims or Disputes**: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

8) Procedures if The PTO is Unable to Complete New Transmission Facilities for Firm Local Point-To-Point Service

a) **Delays in Construction of New Facilities**: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the PTO shall promptly notify the Transmission Customer. In such circumstances, the PTO shall within, thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The PTO also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the PTO that is reasonably needed by the Transmission Customer to evaluate any alternatives.

b) **Alternatives to the Original Facility Additions**: When the review process of Section I.8.a of this Schedule 21 determines that one or more alternatives exist to the originally planned construction project, the PTO shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request that the ISO file a revised Local Service Agreement for Firm Local Point-To-Point Service. If the alternative approach solely involves Non-Firm Local Point-To-Point Service, the PTO shall so inform the ISO, and the ISO (in consultation with the PTO) shall thereafter promptly tender to the Transmission Customer a Local Service Agreement for Non-Firm Local Point-To-Point Service providing for the service. In the event the PTO concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures of Section I.6 of the Tariff.

c) **Refund Obligation for Unfinished Facility Additions**: If the PTO and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested Firm Local Point-To-Point Service cannot be provided out of existing capability, the obligation to provide the requested service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the ISO and the PTO through the time construction was suspended, including costs for removal of unfinished facilities and any ongoing operating expenses of the unfinished facilities until they are removed.

9) **Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities**

a) Responsibility for Third-Party System Additions: The PTO shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The PTO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

b) Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified, and if such upgrades further require the addition of transmission facilities on other systems, the PTO shall have the right to coordinate construction on its own system with the construction required by others. The PTO, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The PTO shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the PTO of its intent to defer construction, the Transmission Customer may challenge the decision in accordance with Section I.6 of the Tariff.

10) Changes in Service Specifications

a) Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Local Point-To-Point Service from a PTO may request transmission service on a non-firm basis over Receipt and Delivery Points of the same PTO other than those specified in the Local Service Agreement ("Secondary Receipt and Delivery Points") in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Local Point-To-Point Service charge or executing a new Local Service Agreement, subject to the following conditions. A Transmission Customer may request a modification to its Non-Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.6. (a) and (b), as appropriate.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the PTO on behalf of its Native Load Customers.

(b) The sum of all Firm Local and Non-Firm Local Point-To-Point Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Local Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Local Point-To-Point Service at the Receipt and Delivery Points specified in the relevant Local Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Local Point-To-Point Service under the Tariff. However, all other requirements of this Schedule 21 (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

b) Modification On a Firm Basis: Any request by a Transmission Customer to modify the Firm Local Point-to-Point Service it receives from a PTO to obtain service between different Receipt and Delivery Points on the Local Network of the same PTO on a firm basis shall be treated as a new request for service, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Local Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Local Service Agreement. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO, which must be made pursuant to Sections I.5. (a) and (b), as appropriate.

11) Sale or Assignment of Transmission Service

a) Procedures for Assignment or Transfer of Service: A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Local Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Local Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee. The Assignee must execute a service agreement with the PTO governing reassignments of transmission service prior to the date on which the reassigned service commences. The PTO shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Local Service Agreement with the PTO or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the PTO or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Local Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of the Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the PTO pursuant to Section I.1.b of this Schedule 21. A Transmission Customer may request a modification to its Firm Local Point-to-Point Service by making such a request to the PTO and the ISO must be made pursuant to sections I.5. (a) and (b) and I.6. (a) and (b), as appropriate.

b) Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Local Service Agreement, the PTO will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the New England Transmission System or the PTO's distribution system, as applicable. The Assignee shall compensate the ISO and/or the PTO, as applicable, for performing any System Impact Study needed to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Local Service Agreement, except as specifically agreed to by the PTO and Reseller through an amendment to the Local Service Agreement

c) Information on Assignment or Transfer of Service: In accordance with Section I.11 of this Schedule 21 and applicable provisions of the Local Service Schedules, all sales or assignments of capacity must be conducted through or otherwise posted on the PTO's OASIS on or before the date the reassigned Local Point-to-Point Service commences and are subject to Section I.11.a of this Schedule 21. Resellers may also use the OASIS to post transmission capacity available for resale.

12) Metering and Power Factor Correction at Receipt and Delivery Points(s)

a) Transmission Customer Obligations: Unless otherwise provided in the applicable Local Service Schedule, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted through Local Point-To-Point Service and to communicate the information to the PTO, Local Control Centers and the ISO. Such equipment shall remain the property of the Transmission Customer.

b) PTO Access to Metering Data: The PTO shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Local Service Agreement.

c) Power Factor: In accordance with Good Utility Practice and any applicable Local Service Schedule, the Transmission Customer is required to maintain a power factor within the same range as the PTO. The power factor requirements are specified in the Local Service Agreement where applicable.

13) Compensation for Local Point-To-Point Service:
Rates for Firm Local and Non-Firm Local Point-To-Point Service are set forth in the Local Service Schedules.

14) Compensation for New Facilities Costs:
Whenever a System Impact Study performed in connection with the provision of Firm Local Point-To-Point Service identifies the need for new facilities, the Transmission Customer shall be responsible for the costs of the new facilities to the extent consistent with Commission policy.

II. LOCAL NETWORK SERVICE

Preamble
Eligible Customers seeking Local Network Service on a specific Local Network shall refer to the applicable Local Service Schedule to determine any PTO-specific rates, terms, and conditions applicable to such service. Except as otherwise provided in the Local Service Schedules, Local Network Service will be provided pursuant to the applicable rates, terms and conditions set forth below.

1) Nature of Local Network Service
Local Network Service is provided to Network Customers to serve their loads. It includes transmission service for the delivery to a Network Customer of its energy and capacity from Network Resources and delivery to or by Network Customers of energy and capacity from New England Markets transactions.

2) Availability of Local Network Service

a) Eligibility to Receive Local Network Service: Transmission Customers taking Regional Network Service must also take Local Service.

b) **Compliance With State Law**: A Network Customer 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 PTO and distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs.

c) **Scope of Service**: Local Network Service allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Local and Regional Network Load and any additional load that may be designated pursuant to the Tariff. The Network Customer taking Local Network Service must obtain or provide Ancillary Services.

d) **PTO Responsibilities**: The PTO in accordance with the TOA will plan, construct, operate and maintain its Local Network in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Local Network Service. Each PTO, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer. This information must be consistent with the information used by the PTO to calculate available transfer capability. The PTO in accordance with the TOA shall include the Network Customer's Local Network Load in Local Network planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver Network Resources to serve the Network Customer's Local and Regional Network Load on a basis comparable to the PTO's delivery of its own generating and purchased resources to its Native Load Customers.

e) **Comparability of Service**: Local Network Service will be provided to the Network Customer for the delivery of energy and/or capacity from its resources to serve its Local and Regional Network Loads on a basis that is comparable to the PTO's use of its Local Network to reliably serve Native Load Customers.

f) **Real Power Losses**: Real Power Losses are associated with all transmission service. The PTOs are not obligated to provide Real Power Losses. Non-PTF Real Power Losses shall be calculated and charged for in accordance with the applicable Local Service Schedule.

g) **Secondary Service**: The Network Customer may use the Local Network to deliver energy to its Local Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as available basis, at no additional charge. Secondary service shall not require the filing of an Application for Local Network Service under Section II of this Schedule 21. However, all other requirements of Section II of this Schedule 21 (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non Firm Local Point To Point Service.

h) Restrictions on Use of Service: The Network Customer shall not use Local Network Service for (i) sales of capacity and energy to non designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Local Network Service shall use Local Point To Point Service for any Third Party Sale, which requires use of the Local Network. The PTO shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Local Network Service or secondary service pursuant to Section II.2.g of this Schedule 21 to facilitate a wholesale sale that does not serve Local Network Load.

3) Initiating Service

a) Condition Precedent for Receiving Service: Local Network Service shall be provided only if the following conditions are satisfied by the Eligible Customer: (i) the Eligible Customer completes an Application to the ISO for service, (ii) the Eligible Customer and the PTO complete the technical arrangements, and (iii) the Eligible Customer executes a Local Service Agreement with the PTO and the ISO or requests in writing that the ISO file an unexecuted Local Service Agreement containing terms and conditions deemed by the PTO (in consultation with the ISO) to be appropriate for such requested service with the Commission.

4) Procedures for Arranging Local Network Service

a) Pre-RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternate Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of their existing Local Service Agreement that is in effect prior to February 1, 2005 (“Pre-RTO Local Service Agreement”), shall not be required to complete an Application or execute a Local Service

Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement may be required. The Transmission Customer shall contact the PTO to discuss and, if appropriate, modify the existing Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of its existing Local Service Agreement that is in effect prior to February 1, 2005 ("Pre-RTO Local Service Agreement"), shall contact the PTO to make arrangements to terminate the Transmission Customer's existing Local Service Agreement and shall complete (and submit to the ISO) an Application for Local Service and then execute a Local Service Agreement under this Schedule 21.

b) RTO Local Service Agreements

(i) A Transmission Customer who wishes to revise the Local Service Agreement termination date, transfer Local Service Agreement ownership, request an alternative Point of Receipt or Point of Delivery, or make upgrades (i.e., increase MWs served) within the terms of the existing Local Service Agreement under this Schedule 21, shall not be required execute a new Local Service Agreement under this Schedule 21, however, modifications to the existing Local Service Agreement under this Schedule 21 may be required. Such modifications to an existing Local Service Agreement typically do not require an additional Local or Regional System Impact Study to be completed. The Transmission Customer shall complete (and submit to the ISO) an application for Local Transmission Service that reflects the requested modifications to the Local Service Agreement to facilitate revision of its existing Schedule 21 Local Service Agreement.

(ii) A Transmission Customer who wishes to make upgrades (i.e., increase MWs served) beyond the terms of the existing Local Service Agreement under this Schedule 21, shall contact the ISO to discuss and, if appropriate, terminate the Transmission Customer's existing Local Service Agreement under this Schedule 21 and shall complete (and submit to the ISO) a new Application for Local Service and then execute a new Local Service Agreement under this Schedule 21.

c) Application Procedures: An Eligible Customer requesting Local Network Service must submit an Application, with a deposit equal to the charge for one month of service, unless another charge is specified in the applicable Local Service Schedule, to the ISO as far as possible in advance of the month in which service is to commence. Completed Applications for Local Network Service will be assigned a reservation priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer;

(iii) A description of the Local Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each substation at the same transmission voltage level. The description should include a ten-year forecast of summer and winter load resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Local Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten-year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten-year projection), which shall include, for each Network Resource, if the description is not otherwise available to the ISO and the PTOs:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules
- Minimum loading level of unit

- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Approximate variable dispatch price ($/MWH), consistent with Market Rule 1, for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the New England Control Area, where only a portion of unit output is designated as a Network Resource
- Description of external purchased power designated as a Network Resource including source of supply, control area location, transmission arrangements and delivery point(s);

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the ISO and the PTOs
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Local Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- ten-year projection of system expansions or upgrades
- transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested service. The minimum term for service is one year; and

(viii) Any additional information required of the Transmission Customer as specified in the PTO's planning process established in Attachment K.

Unless the Eligible Customer and the ISO agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Local Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this Section, the PTO shall notify the ISO within ten (10) days of the Application's receipt of the reasons for such failure, and the ISO shall, in turn, so notify the entity requesting service within five (5) days of the receipt of notice from the PTO of the reasons for such failure. Wherever possible, the ISO and the PTO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application without prejudice to the Eligible Customer, who may thereafter file a new or revised Application that fully complies with the requirements of this Section. The Eligible Customer will be assigned a new reservation priority consistent with the date of the new or revised Application. The ISO and the PTO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

d) Technical Arrangements to be Completed Prior to Commencement of Service: Local Network Service shall not commence until the PTO and the Network Customer, or a third party, have completed installation of all equipment specified under the Local Service Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Non-PTF. The PTO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

e) Network Customer Facilities: The provision of Local Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Non-PTF to the Network Customer. The Network Customer shall be solely responsible for constructing or installing and operating and maintaining all facilities on the Network Customer's side of each such delivery point or interconnection.

f) Filing of Service Agreement: The ISO shall file Local Service Agreements with the Commission in compliance with applicable Commission regulations.

5) Network Resources

a) Designation of Network Resources: The Network Customer shall designate those Network Resources which are owned, purchased or leased by it. The Network Resources so designated may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Local Network Load on a non-interruptible basis. Any owned, purchased or leased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Compliance Effective Date shall be deemed to continue to be so owned, purchased or leased by it until the Network Customer informs the ISO and the PTO of a change.

b) Designation of New Network Resources: The Network Customer shall identify any new Network Resources which are owned, purchased or leased by it with as much advance notice as practicable. A designation of any new Network Resource as owned, purchased or leased by the Customer must be made by a notice to the ISO and the PTO.

c) Termination of Network Resources: The Network Customer may terminate the designation of all or part of a Network Resource as owned, purchased or leased by it at any time but shall provide notification to the ISO and the PTO as soon as reasonably practicable.

d) Network Customer Redispatch Obligation: As a condition to receiving Local Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO and the PTO. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate External Transactions. The Network Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

e) Transmission Arrangements for Network Resources Not Physically Interconnected with the PTO's Non-PTF: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the PTO's Non-PTF. The applicable PTO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

f) Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under this Schedule 21.

g) Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the PTO's Local Network may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration, the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the PTO to serve all of its power and transmission customers. For facilities added by the Network Customer subsequent to the effective date of a Final Rule in RM05-25-000, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the PTO's facilities; provided however, the Local Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the PTO, would be eligible for inclusion in the PTO's annual transmission revenue requirement as specified in the PTO's respective Local Service Schedule. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

6) Designation of Local Network Load

a) Local Network Load: The Network Customer must designate the individual Local Network Loads which it expects to have served through Local Network Service. The Local Network Loads shall be specified in the Local Service Agreement.

b) New Local Network Loads Within the New England Control Area: The Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable of the designation of new Local Network Load that will be added to the Non-PTF. A designation of new Local Network Load must be made through a modification of service pursuant to a new Application. The PTO will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Local Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Local Network Load shall be determined in accordance with the procedures provided in this Schedule 21 and shall be charged to the Network Customer in accordance with Commission policy and this Schedule 21.

c) Local Network Load Not Physically Interconnected with the PTO: This Section applies to both initial designation and the subsequent addition of new Local Network Load not physically interconnected with the PTO's Non-PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the Local Network, the Network Customer shall have the option of

(1) electing to include the entire load as Local Network Load for all purposes under this Schedule 21 and designating Network Resources in connection with such additional Local Network Load, or (2) excluding that entire load from its Local Network Load and purchasing Local Point To Point Service under this Schedule 21. To the extent that the Network Customer gives notice of its intent to add a new Local Network Load as part of its Local Network Load pursuant to this Section the request must be made through a modification of service pursuant to a new Application.

d) **New Interconnection Points**: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Non-PTF and a Local Network Load, the Network Customer shall provide the ISO and the PTO with as much advance notice as reasonably practicable.

e) **Changes in Service Requests**: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Local Network Service (the addition of a new Network Resource, if any, or designation of a new Local Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the PTOs and charged to the Network Customer as reflected in the applicable Local Service Agreement or other appropriate agreement. However, the PTO must treat any requested change in Local Network Service in a non-discriminatory manner.

f) **Annual Load and Resource Information Updates**: The Network Customer shall provide the ISO and the PTO with annual updates of Local Network Load and Network Resource forecasts consistent with those included in its Application including, but not limited to, any information provided under Section II.3.b of this Schedule 21 pursuant to the PTO's planning process in Attachment K. The Network Customer also shall provide the ISO and the PTO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Local Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the PTO to provide reliable service.

7) **Additional Study Procedures For Local Network Service Requests**

a) **Notice of Need for System Impact Study**: After receiving a request for Local Network Service, a determination shall be made on a non-discriminatory basis as to whether a System Impact Study is needed. The ISO shall review the request to determine whether the provision of the requested service would have an impact on facilities other than Non-PTF, and if so, whether a System Impact Study is necessary to accommodate the requested service. If so, the ISO shall so inform the Eligible Customer as soon as practicable and will (in consultation with the PTO) perform a System Impact Study, as necessary, with respect to the request. A description of the ISO's methodology for completing a System Impact Study is provided in OATT Attachment D. If the ISO determines that the service would not have an impact on facilities other than Non-PTF, the PTO shall determine whether a System Impact Study is necessary to accommodate the requested service and shall so inform the Eligible Customer as soon as practicable and will (in consultation with the ISO) perform a System Impact Study, as necessary, with respect to the application. In such cases, the ISO or the PTO, as applicable, shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO or the PTO, as applicable, for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the ISO or the PTO, as applicable, within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. A description of the PTO's methodology for completing a System Impact Study is provided in its Local Service Schedule.

b) System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify an estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study shall rely on existing transmission planning studies to the extent reasonably practicable. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Local Network.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the PTO conducts on its own behalf, the PTO shall record the cost of the System Impact Studies pursuant to Section II.8.5 of the Tariff.

(iv) In response to multiple Eligible Customers within the same electrically interconnected area requesting clustering of system Impact Study analysis for Local Service, the PTO will accommodate such multiple requests if it can reasonable do so. The costs of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis.

c) System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints, additional Direct Assignment Facilities or Local Network Upgrades required to provide the requested service. In the event that the ISO or the PTO, as applicable, is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The PTO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The ISO or the PTO, as applicable, shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Local Network will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study, the Eligible Customer must execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement pursuant to Section II.3.a of this Schedule 21 or the Application shall be deemed terminated and withdrawn.

d) Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to facilities other than Non-PTF are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the ISO for performing the required Facilities Study. If a System Impact Study indicates that additions or upgrades to Non-PTF facilities are needed to supply the Eligible Customer's service request or to mitigate indirect impacts on the MTF facilities, the PTO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the PTO for performing the required Facilities Study. For clustered studies, the cost of such studies shall be pro-rated among the Eligible Customers on an agreed upon basis. For a service request to remain a Completed

Application, the Eligible Customer shall execute the Facilities Study Agreement and return it within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the ISO or the PTO, as applicable, will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Facilities Study cannot be completed in the allotted time period, the Eligible Customer shall be notified and provided an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Local Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the PTO equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Local Service Agreement or request the filing of an unexecuted Local Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study shall, if requested by the Eligible Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion.

e) **Facilities Study Modifications**: Any change in design arising from the inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the ISO and/or the PTO that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer.

f) **Due Diligence in Completing New Facilities**: The PTO shall use due diligence to add necessary facilities or upgrade its Local Network within a reasonable time. The PTO will not upgrade its existing or planned Local Network in order to provide the requested Local Network Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

g) Claims or Disputes: Any claim or dispute between the PTO and the Transmission Customer with respect to a System Impact Study or Facilities Study shall be governed by the provisions of Section I.6 of the Tariff.

h) Penalties for Failure to Meet Study Deadlines: Section I.7.i of this Schedule 21 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Section I of this Schedule 21. These same requirements and penalties apply to service under Section II of this Schedule 21.

8) Load Shedding and Curtailments

a) Procedures: The PTO shall establish Load Shedding and Curtailment procedures (consistent with those of the ISO and the Local Control Center) with the objective of responding to contingencies on the Non-PTF. The PTO will notify all affected Local Network Service Customers in a timely manner of any scheduled Curtailment.

b) Transmission Constraints: During any period when a PTO or the Local Control Center determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, the PTO or the Local Control Center will so inform the ISO. The ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the New England Transmission System can be maintained by redispatching resources, The ISO will initiate procedures to redispatch all resources on a least-cost basis without regard to the ownership of such resources.

c) Cost Responsibility for Relieving Transmission Constraints: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customer will bear the costs of such redispatch in accordance with Market Rule 1.

d) Curtailments of Scheduled Deliveries: If a transmission constraint on the Non-PTF cannot be relieved through the implementation of least-cost redispatch procedures and the PTO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with the terms of the Tariff.

e) Allocation of Curtailments: The ISO, the Transmission Owner or the Local Control Center shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service and OTF Service and/or Through or Out Service and Network Customers on a non-discriminatory basis. Notwithstanding the preceding provisions of this Section, External Transactions shall be scheduled and curtailed in accordance with Section II.44 of the OATT.

f) Load Shedding: Load Shedding also may occur in accordance with the applicable Local Service Schedule to the extent provided for in such Local Service Schedule.

g) System Reliability: Notwithstanding any other provisions of this Schedule, The ISO, the PTO and the Local Control Centers reserve the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of service without liability on the part of the ISO, the PTO or the Local Control Centers for the purpose of making necessary adjustments to, changes in, or repairs on the PTO's lines, substations and facilities, and in cases where the continuance of service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Non-PTF or on any other system(s) directly or indirectly interconnected with the Non-PTF, the ISO, the PTO and the Local Control Centers, consistent with Good Utility Practice, also may effect a Curtailment of service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO, the PTO or the Local Control Centers will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Local Network Service will be not unduly discriminatory relative to the PTO's use of the New England Transmission System on behalf of their Native Load Customers. The Local Service Schedules shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

9) Rates and Charges

The Network Customer shall pay all applicable charges for Local Network Service set forth in this Schedule 21, including the Local Service Schedules, and for any Direct Assignment Facilities and its share of the cost of any required Local Network Upgrades and applicable study costs consistent with Commission policy, along with any additional charges imposed under the Tariff. In the event the

Network Customer serves Local Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for each Local Network.

10) Determination of Network Customer's Monthly Network Load

For purposes of Local Network Service, the Network Customer's "Monthly Network Load" shall be determined in accordance with the applicable Local Service Schedule.

11) Operating Arrangements

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the terms of the Tariff. The terms and conditions under which the Network Customer taking Local Network Service shall operate its facilities and the technical and operational matters associated with the implementation of Local Network Service shall be specified in Section II.22 of the Tariff and/or the Local Service Schedules.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of ______________, is entered into, by and between _______________ , a ________________organized and existing under the laws of the State/Commonwealth of _____________ ("Transmission Owner"), ____________ , a ________________organized and existing under the laws of the State/Commonwealth of _____________ ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

__ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:

____

____

____

Transmission Owner:

____

____

____

The ISO:

____

____

____

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act

and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Specifications for Local Network Service.

    a. Term of Service:

    b. List of Network Resources and Point(s) of Receipt:

    c. Description of capacity and energy to be transmitted:

    d. Description of Local Network Load:

    e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

    f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent’s authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

q. Additional terms and conditions:

4. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

   c. Point(s) of Receipt:

   d. Delivering Party:

   e. Point(s) of Delivery:

   f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:______________________ ________________ ______________

Name Title Date

____

Print Name

Transmission Owner:

By:______________________ ________________ ______________

Name Title Date

____

Print Name

The ISO:

By:______________________ ________________ ______________

Name Title Date

____Print Name

SCHEDULE 21

ATTACHMENT A-1

Form of Local Service Agreement For The Resale, Reassignment or Transfer of Point-To-Point Transmission Service

1.0 This LOCAL SERVICE AGREEMENT, dated as of ______________, is entered into, by and between ________________ , a _________________organized and existing under the laws of the State/Commonwealth of _____________ ("Transmission Owner"), ____________ , a ________________organized and existing under the laws of the State/Commonwealth of _____________ ("Assignee") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Assignee, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

2.0 The Assignee has been determined by the Transmission Owner to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Local Service Agreement shall be subject to the terms and conditions of Part I of Schedule 21 and the Transmission Owner's Local Service Schedule of Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section I.11.a of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section I.11.b of this Tariff.

4.0 The Transmission Owner shall credit the Reseller for the price reflected in the Assignee's Local Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Local Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Owner:

____

____

____

The ISO:

____

____

____

Assignee:

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Owner:

By:____________________ ________________________ _______________

Print Name: Title: Date:

The ISO:

By:____________________ ________________________ _______________

Print Name: Title: Date:

Assignee:

By:___________________ ________________________ ________________

Print Name: Title: Date:

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ______________________________

Start Date: ______________________________

Termination Date: ______________________________

2.0 Description of capacity and energy to be transmitted by Transmission Owner including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:______________________________

Delivering Party:______________________________

4.0 Point(s) of Delivery:______________________________

Receiving Party:______________________________

5.0 Maximum amount of reassigned capacity: ______________

6.0 Designation of party(ies) subject to reciprocal service obligation:______________________________

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:______________________________

____

(Name of Transmission Owner) Open Access Transmission Tariff

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:____________________

____

8.4 Ancillary Services Charges: ______________________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

III.5 Transmission Congestion Revenue & Credits Calculation

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

III.5.1.1 Calculation by ISO.

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

III.5.1.2 General.

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

III.5.1.3 [Reserved.]

III.5.1.4 Non-Market Participant Transmission Customer Calculation.

Congestion Costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Congestion Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Congestion Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface. Non-Market Participants using Point-to-Point Transmission Service for deliveries through the New England Control Area shall be included in the determination of the Congestion Costs.

III.5.2 Transmission Congestion Credit Calculation.

III.5.2.1 Eligibility.

Except as provided in Section III.A.8.4 of Appendix A, each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total monthly Transmission Congestion Revenues collected.

III.5.2.2 Financial Transmission Rights.

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

(b) FTRs shall be awarded to winning bidders in the FTR Auctions pursuant to Section III.7.

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

(ii) An entity that acquires an FTR through the FTR Auction may elect to hold it, or sell it in the FTR Auction. The ISO shall settle FTRs only with the registered FTR Holders. At any given time, each FTR shall have only one registered FTR Holder.

III.5.2.3 [Reserved.]

III.5.2.4 Target Allocation to FTR Holders.

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

III.5.2.5 Calculation of Transmission Congestion Credits.

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

(b) The sum of all monthly positive target allocations, as determined in Section III.5.2.4, shall be compared to the Transmission Congestion Revenue for the current month. If the sum of all monthly positive target allocations is less than the Transmission Congestion Revenue for the current month, the Transmission Congestion Credit for each FTR Holder shall be equal to its total monthly positive target allocation. All remaining Transmission Congestion Revenues from the current month shall be carried over to the end of the calendar year.

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

III.5.2.6 Distribution of Excess Congestion Revenue.

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

III.7 Financial Transmission Rights Auctions

III.7.1 Auctions of Financial Transmission Rights.

Periodic auctions ("FTR Auctions") to allow Eligible FTR Bidders to acquire or FTR Holders to sell FTRs shall be conducted by the ISO in accordance with the provisions of this Section. Non-Market Participants that want to participate in the FTR Auction and have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of $5,000.

III.7.1.1 Auction Period and Scope of Auctions.

(a) FTR Auctions shall be held on an annual and monthly basis.

(b) The annual FTR Auction shall be conducted for FTRs effective for a single calendar year in two sequential rounds. Twenty-five percent of the available network capacity shall be available for the initial round of the annual FTR Auction. The FTRs that remain feasible with fifty percent of the network capacity available and after deducting the network capability associated with FTRs sold in the initial round shall be made available during the second round of the annual FTR Auction.

(c) The ISO shall conduct monthly FTR Auctions, after the completion of the annual FTR Auction, every month. A monthly FTR shall be effective for a single full calendar month. The monthly FTR Auctions shall include separate auctions for every remaining month in the calendar year. FTRs shall be made available for monthly auctions as follows:

(i) When FTRs for a month are auctioned for the final time, all FTRs that remain feasible will be made available, after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

(ii) For all other monthly auctions all FTRs that remain feasible with fifty percent of the network capacity available will be made available after accounting for all FTRs transacted in the annual FTR Auctions and all FTRs transacted in previous auctions for the relevant month.

III.7.1.2 FTR Auctions Assumptions.

For annual FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 90 days prior to the first effective day of the FTRs to be auctioned. For monthly FTR Auctions, the auction assumptions, including the modeling assumptions to be used for the FTR Auctions and dates and times for the opening and closing of bid submission windows will be announced by the ISO no later than 40 days prior to the first effective day of the FTRs to be auctioned.

III.7.2 Financial Transmission Rights Characteristics.

III.7.2.1 Reconfiguration of Financial Transmission Rights.

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

III.7.2.2 Specified Locations.

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

III.7.2.3 Transmission Congestion Revenues.

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

III.7.2.4 [Reserved.]

III.7.3 Auction Procedures.

III.7.3.1 Role of the ISO.

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

III.7.3.2 [Reserved.]

III.7.3.3 [Reserved.]

III.7.3.4 On-Peak and Off-Peak Periods.

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

III.7.3.5 Offers and Bids.

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

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

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

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

III.7.3.6 Determination of Winning Bids and Clearing Price.

(a) At the close of each bidding period, the ISO will create a base FTR power flow model that includes all outstanding FTRs that have previously been awarded for the period for which the auction was conducted and that were not offered for sale in the auction. The base FTR model for the annual FTR Auction will reflect the network topology and transmission operating limits in effect at the time the annual FTR Auction is conducted, adjusted for estimated scheduled transmission outages. Monthly FTR Auctions (other than for the first month in the series of remaining months in the calendar year) shall utilize the same base network topology and transmission operating limits as used in the annual FTR Auction. The auction for the first month in the series of remaining months in the calendar year shall utilize the then current network topology and transmission operating limits, as adjusted for currently estimated scheduled transmission outages and outages of individual generating units to the extent that such outages impact voltage or stability limits. The base FTR models also will include estimated uncompensated parallel flows into each interface point of the New England Control Area.

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

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

III.7.3.7 Announcement of Winners and Prices.

(a) After the close of the first round of the annual FTR Auction, in accordance with the schedule published in the auction assumptions and prior to the open of the bidding window for the final-round annual auctions, the ISO shall post the auction prices and FTRs cleared between eligible bidding locations, as specified in Section III.7.2.2, excluding the identity of the winning bidder. The identities of winning bidders and the quantities of FTRs cleared by individual bidders in the first round of the annual auction will not be published until the close of the final round of the annual FTR Auction.

After the close of the final round of the annual FTR Auction, the ISO shall post, in accordance with the schedule set forth in the auction assumptions and prior to the open of the bidding window for monthly auctions, the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the annual auction and the price at which each FTR was awarded.

(b) After the close of the monthly FTR Auction process, in accordance with the schedule set forth in the auction assumptions and prior to the effective date of the auctioned FTRs, the ISO shall post the winning bidders, the megawatt quantity, and the receipt and delivery points for each FTR awarded in the auction and the price at which each FTR was awarded. The FTR awards and prices shall be final as posted and not subject to correction or other adjustment, and shall be used for purposes of settlement, except as provided in subsections (d) and (e).

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

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

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

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

III.7.3.8 Auction Settlements.

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

III.7.3.9 Allocation of Auction Revenues.

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

III.7.3.10 Simultaneous Feasibility.

The ISO shall make the simultaneous feasibility determinations specified herein using appropriate power flow models of contingency-constrained dispatch. Such determinations shall take into account outages, network model-related changes, and expected configuration of transmission facilities in accordance with Section III.7.3.6(a).. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient Transmission Congestion Revenues to satisfy all FTR obligations for the auction period under expected conditions.

III.7.3.11 [Reserved.]

III.7.3.12 Financial Transmission Rights in the Form of Options.

When the ISO has the necessary software and hardware, the FTR Auctions shall allow for the acquisition of FTRs that do not create potential obligations to pay.

SECTION III

MARKET RULE 1

APPENDIX C

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

APPENDIX C

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

Table of Contents

AUCTION REVENUE RIGHTS AND INCREMENTAL ARRs

III.C.1 Introduction.

Auction Revenue Rights ("ARRs") are rights to receive FTR Auction Revenues from the sale of FTRs other than FTRs sold by FTR Holders. Incremental ARRs are rights to receive FTR Auction Revenues associated with transmission system upgrades, as provided in Section III.C.8. ARRs shall be determined and allocated to Congestion Paying LSEs, Transmission Customers and NEMA LSEs (including any of the foregoing that are parties to Excepted Transactions that are included in the list of transactions specified in Attachments G and G-2 of the Transmission, Markets and Services Tariff), using a four-stage process as described below (the "ARR Allocation"). Congestion Paying LSEs that are Asset Related Demands or Dispatchable Asset Related Demands will receive ARR allocations based on the specific relevant Node for each Asset.

Auction Revenue Rights are determined at the completion of each month to distribute the net FTR Auction Revenues (which excludes FTR Auction Revenues attributable to FTRs sold at auction by FTR Holders) associated with that month, including a monthly share of all net revenues from annual FTR Auctions that include that particular month based on the number of days in the month divided by the number of days in the year, and including the net auction revenues from all monthly auctions for FTRs effective for that particular month. The ARR determination for revenues associated with annual on-peak or off-peak FTR Auctions shall be based on the auction prices resulting from the specific annual on-peak or off-peak auction. The ARR determination for revenues associated with monthly on-peak FTR Auctions shall be based on the auction prices in the final on-peak auction for the month. The ARR determination for revenues associated with monthly off-peak FTR Auctions shall be based on the auction prices in the final off-peak auction for the month.

III.C.2 First Stage ARR Allocation

III.C.2.1 Excepted Transactions.

In the first stage of each ARR Allocation, each entity serving load to which energy is delivered or making an External Transaction sale pursuant to an Excepted Transaction included in the list of transactions specified in Section II.41 of Section II of the Transmission, Markets and Services Tariff, and which is the party responsible for paying Congestion Cost associated with energy purchased under the Excepted Transaction shall have the option to be allocated ARRs from the generator to the location of the load or

External Node. Alternatively, each seller delivering energy pursuant to an Excepted Transaction to an entity serving load or making an External Transaction sale and in which the seller is the party responsible for paying Congestion Cost associated with energy purchased under the Excepted Transaction shall have the option to be allocated ARRs from the generation source to the location of the load or External Node. For an Excepted Transaction which is not an External Transaction, if the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction does not elect to be allocated ARRs under Section III.C.2.1, then the ARRs associated with the destination Node(s) of the load served by such Excepted Transaction shall be allocated pursuant to Section III.C.2.2.
The party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction which is an External Transaction will retain its existing contract rights for physical scheduling of such transaction pursuant to Section II of the Transmission, Markets and Services Tariff until such party irrevocably elects to be allocated ARRs under this Section III.C.2. Such irrevocable election shall mean that the party may not revert to using its contract rights for physical scheduling. For an Excepted Transaction which is an External Transaction purchase, the party may request to be allocated ARRs, prior to each FTR Auction, either pursuant to Section III.C.2.1 or pursuant to Section III.C.2.2. For an Excepted Transaction which is an External Transaction, if the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction does not elect to be allocated ARRs under Section III.C.2.1, then the ARRs associated with the destination Node(s) of the load served by such Excepted Transaction shall be allocated pursuant to Section III.C.2.2. For an Excepted Transaction which is an External Transaction sale, ARRs will be allocated pursuant to Section III.C.2.1.

III.C.2.1.1 Requesting Allocation of First Stage ARRs for Excepted Transactions.

In order to be eligible to receive ARRs in association with an Excepted Transaction, each entity to which energy is delivered pursuant to an Excepted Transaction or which delivers energy pursuant to an Excepted Transaction must request that it be allocated ARRs pursuant to this Section III.C.2.1 and in accordance with the ISO New England Manuals and ISO New England Administrative Procedures prior to each FTR Auction.

III.C.2.1.2 Specification of First Stage ARRs for Excepted Transactions.

The first stage ARR Allocation to an entity serving load to which energy is delivered or making an External Transaction sale pursuant to an Excepted Transaction who makes such a request shall be equal to the number of megawatts of energy to be delivered to that customer under the Excepted Transaction. The origin Node(s) or External Node(s) for those ARRs shall match the generation source for any such

Excepted Transaction and the destination Node(s) for those ARRs shall match the location: (i) of the load served by those Excepted Transactions or (ii) of the External Node if the Excepted Transaction is an External Transaction sale. The first stage ARR Allocation to an entity selling energy to an entity serving load or making an External Transaction sale to which energy is delivered pursuant to an Excepted Transaction who makes such a request shall be equal to the number of megawatts of energy to be delivered by that selling entity under the Excepted Transaction. The origin Node(s) or External Node(s) for those ARRs shall match the generation source for any such Excepted Transaction and the destination Node(s) for those ARRs shall match the location: (i) of the load served by those Excepted Transactions or (ii) of the External Node if the Excepted Transaction is an External Transaction sale. Each entity shall be entitled to make requests for ARRs under the terms of this section until the Excepted Transaction has terminated, or ten years from the SMD Effective Date, whichever is earlier.

III.C.2.2 Transmission Customers and Congestion Paying LSEs.

ARRs shall be allocated to each Congestion Paying LSE and Transmission Customer from each generating Resource and tie line source in proportion to the capacity of the generator and tie line source and in proportion to the loads in the network model for the FTR Auction for the period being settled.

The generator or tie line source and load associated with each Excepted Transaction shall be reduced by the MW quantity of the Excepted Transaction. The determination of the first stage ARR Allocation to Transmission Customers and Congestion Paying LSEs shall be performed using the following formula:

$$N_{ijt} = G_{it} * (L_{jt}/L_t),$$

where:

N_{ijt} = the amount of ARRs from Node or External Node i to Node or External Node j for the period being settled t;

G_{it} = the total rated capacity for month *t* of generators or the capacity during period *t* of tie line capacity located at Node *i*;

L_{jt}= the load at Node *j* from the network model used for the FTR Auction for period *t*, updated as appropriate, less any portion of that load which is associated with Excepted Transactions as described above; and

L_t = total load from the network model used for the FTR Auction for period *t*, updated as appropriate, less any portion of that load which is associated with all Excepted Transactions as described above.

The total quantity of ARRs assigned to load pursuant to this Section III.C.2.2 in period *t* shall be:

$$\sum_i \sum_j N_{ijt}$$

III.C.3 Second Stage of ARR Allocation

III.C.3.1 In General.

The amount of ARRs allocated to each entity in the first stage of each ARR Allocation may be modified in the second stage of that ARR Allocation. The second stage of each ARR Allocation shall determine the final allocation of ARRs to all ARR Holders for that FTR Auction, except for NEMA LSEs. Allocations of ARRs to NEMA LSEs may be modified in the third and fourth stages of the ARR Allocation for each FTR Auction.

III.C.3.2. The Second Stage Allocation Procedure.

The second stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, and the termination or expiration of Excepted Transactions. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures. For each FTR Auction:

Step 1: Begin with the combination of all ARRs included in the first-stage ARR Allocation described in Section III.C.2.

Step 2: Determine a value for each ARR using the on-peak or off-peak auction prices, as applicable, pursuant to Section III. C.1.

Step 3: Through the following steps, eliminate ARRs having a negative value in the FTR Auction and then reduce the set of remaining ARRs defined in Step 1 proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.

3(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction.

3(b): Test whether the ARRs identified in Step 3(a) are simultaneously feasible.

3(c): If the ARRs identified in Step 3(a) are simultaneously feasible, go to Step 4.

3(d): If the ARRs identified in Step 3(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 3(a).

3(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the ARRs defined in Step 3(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all ARRs defined in Step 3(a) that increase flows over this constraint until the constraint is relieved.

3(f): Test whether the ARRs identified in Step 3(e) are simultaneously feasible. If the set of ARRs defined in Step 3(e) is simultaneously feasible, proceed to Step 4.

3(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 3(e).

3(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the ARRs defined in Step 3(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all ARRs defined in Step 3(e) that increase flows over this constraint until the constraint is relieved.

3(i) Repeat Steps 3(f) through 3(h) as necessary until a simultaneously feasible set of ARRs is obtained.

3(j) If as a result of the application of Steps 3(e) through 3(i) any of the constraints over which ARRs were reduced in Steps 3(e) through 3(i) is no longer binding, ARRs defined in Step 3(a) that have been reduced in Steps 3(e) through 3(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

The allocation process ends here if NEMA is not constrained and the ARRs allocated at the conclusion of Step 3(j) constitute the final allocation of ARRs.

Step 4. The ARR Allocation determined in the preceding steps shall be divided into two sets: ARRs allocated to entities that are not NEMA LSEs, and ARRs allocated to NEMA LSEs.

III.C.4 Third Stage of ARR Allocation

III.C.4.1 In General.

The ARRs allocated to NEMA LSEs, as determined in the first two stages of each ARR Allocation, may be modified further in the third and fourth stages of the ARR Allocation. The third and fourth stages of any ARR Allocation shall not change the amount or origin Nodes or External Nodes or destination Nodes of any ARRs allocated to entities that are not NEMA LSEs as of the conclusion of the second stage of that ARR Allocation.

III.C.4.2 Definition of Stage 3 ARRs.

For the purposes of this stage, a set of "Stage 3 ARRs" shall be defined as follows: Certain NEMA LSEs which have long-term purchase contracts in effect as of November 1, 1999 for generation resources with delivery points in NEMA, excluding long-term purchase contracts covered by Excepted Transactions, ("NEMA Contracts") shall be allocated Stage 3 ARRs.

III.C.4.2.1 Verification of NEMA Contracts.

The NEMA Contracts for these NEMA LSEs' respective generation resources and entitlements, which entitle them to Stage 3 ARRs subject to verification that the NEMA Contracts meet the criteria specified in Section III.C.4.2, are listed in ***Exhibit 1*** to this Appendix C. Each NEMA LSE listed in ***Exhibit 1*** shall provide by October 1, 2000 to the ISO and shall make available upon request to each NEMA LSE, copies of its NEMA Contract(s) in the form that such contracts existed as of November 1, 1999, together with copies of any subsequent modifications or amendments, any notices of termination, and any notices or elections shortening the term or reducing the amount of power to be purchased under its NEMA Contract(s). For as long as a NEMA LSE listed in ***Exhibit 1*** has a right to request Stage 3 ARRs, it shall have an ongoing obligation to provide, in a timely manner, each NEMA LSE and the ISO with copies of any further modifications or amendments, any transfers to another entity of the responsibility for paying for the Congestion Cost any notices of termination, and any notices or elections shortening the term or reducing the amount of power to be purchased under its NEMA Contract.

III.C.4.2.2. Specification of Stage 3 ARRs.

The amount of Stage 3 ARRs that will be allocated to each NEMA LSE shall be equal to the sum of the megawatts of entitlement specified in each NEMA LSE's NEMA Contract(s) calculated based on the winter capability period (the period from the beginning of October through the end of May) capacity during months of the winter capability period and the summer capability period (the period from the beginning of June through the end of September) capacity during the months of the summer capability period subject to the limitation that the Stage 3 ARRs allocated to each NEMA LSE shall not exceed that NEMA LSE's Real-Time Load Obligation excluding External Transaction sales at the time of the coincident peak for the New England Control Area for the period being settled. The origin Node(s) or External Node(s) for the Stage 3 ARRs allocated to NEMA LSEs shall match the Node(s) or External

Node(s) where energy was purchased in association with the NEMA Contracts listed in Exhibit 1, and the destination Node(s) for the Stage 3 ARRs allocated to NEMA LSEs shall match the location of the load served by that NEMA LSE in association with that contract.

III.C.4.2.3. Requesting Allocation of Stage 3 ARRs for NEMA Contracts.

The NEMA LSEs identified in ***Exhibit 1*** to this Appendix C shall be entitled to make requests for Stage 3 ARRs under the terms of this section until the earlier of the expiration of the term of each of its NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999, or until NEMA is no longer constrained. To the extent that such a NEMA LSE transfers to another entity the responsibility for paying for the Congestion Cost resulting from the NEMA LSE's NEMA Contract, the entity assuming such responsibility shall receive the entitlement to the NEMA LSE's Stage 3 ARRs in lieu of the NEMA LSE receiving that entitlement.

III.C.4.3. The Third Stage Allocation Procedure.

The third stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, reductions in or resale of purchase amounts under NEMA Contracts, and the termination of the NEMA Contract(s) or expiration of the term of the NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures.

Step 1: Begin with the set of all Stage 3 ARRs.

Step 2: Through the following steps, eliminate Stage 3 ARRs having a negative value in the FTR Auction and then reduce the set of remaining Stage 3 ARRs proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.

2(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction. Then add the set of all non-NEMA ARRs as determined in Step 4 of Stage 2 to the remaining Stage 3 ARRs.

2(b): Test whether the ARRs identified in Step 2(a) are simultaneously feasible.

2(c): If the ARRs identified in Step 2(a) are simultaneously feasible, go to Step 3.

2(d): If the ARRs identified in Step 2(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(a).

2(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 3 ARRs defined in Step 2(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 3 ARRs defined in Step 2(a) that increase flows over this constraint until the constraint is relieved.

2(f): Test whether the ARRs identified in Step 2(e) are simultaneously feasible. If the set of ARRs defined in Step 2(e) is simultaneously feasible, proceed to Step 3.

2(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(e).

2(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 3 ARRs defined in Step 2(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 3 ARRs defined in Step 2(e) that increase flows over this constraint until the constraint is relieved.

2(i) Repeat Steps 2(f) through 2(h) as necessary until a simultaneously feasible set of ARRs is obtained.

2(j) If as a result of the application of Steps 2(e) through 2(i) any of the constraints over which ARRs were reduced in Steps 2(e) through 2(i) is no longer binding, ARRs defined in Step 2(a) that have been reduced in Steps 2(e) through 2(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

Step 3. Remove the non-NEMA ARRs. The remaining ARRs will be the ARRs for the NEMA Contracts.

III.C.5 Fourth Stage of ARR Allocation Procedure

III.C.5.1 In General.

The fourth stage of the ARR Allocation shall determine the final allocation of ARRs for a given FTR Auction. The fourth stage shall only affect the allocation of ARRs to NEMA LSEs.

III.C.5.2 Definition of "Stage 4 ARRs".

For the purposes of this step, a set of "Stage 4 ARRs" shall be defined. The determination of the fourth stage ARR Allocation to NEMA LSEs shall be performed using the following formula:

$$N_{ijt} = A_{ijt} * X_{jt}$$

where:

N_{ijt} = the amount of Stage 4 ARRs from Node or External Node *i* to the load at NEMA Node *j* (from the network model used for the FTR Auction) for the period being settled *t*;

A_{ijt} = the amount of ARRs from Node or External Node *i* to NEMA that had been allocated to the load at NEMA Node *j* for period *t* as of the conclusion of the second stage of the ARR Allocation; and

X_{jt} = the ratio of load at NEMA Node *j* from the network model used for the FTR Auction for period *t*, less any portion of that load which is associated with NEMA Contracts as described above, to the total load at NEMA Node *j* from the network model used for the FTR Auction for period *t*.

III.C.5.3 The Fourth Stage Allocation Procedure.

The fourth stage of each ARR Allocation shall be performed using the following procedure, which will be adjusted on an annual and monthly basis to account for changes in available transmission capacity, load ratio shares, reductions in purchase amounts under NEMA Contracts, and the termination of the NEMA Contract(s) or expiration of the term of the NEMA Contract(s) in effect as of November 1, 1999, but excluding any optional extensions which had not been exercised as of November 1, 1999. The ISO shall make such adjustments in accordance with the allocation methodology described below, in the ISO New England Manuals and in the ISO New England Administrative Procedures.

Step 1: Begin with the set of all Stage 4 ARRs.

Step 2: Through the following steps, eliminate Stage 4 ARRs having a negative value in the FTR Auction and then reduce the set of remaining Stage 4 ARRs proportionately on a per megawatt of constraint impact basis as necessary to arrive at a set of ARRs that is simultaneously feasible in a contingency constrained dispatch.2(a): Identify all ARRs determined in Step 1 that receive a positive value (in $/MW) in the FTR Auction. Then add the set of all non-NEMA ARRs and all ARRs for NEMA Contracts to the remaining Stage 4 ARRs.

2(b): Test whether the ARRs identified in Step 2(a) are simultaneously feasible.

2(c): If the ARRs identified in Step 2(a) are simultaneously feasible, go to Step 3.

2(d): If the ARRs identified in Step 2(a) are not simultaneously feasible, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(a).

2(e): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 4 ARRs defined in Step 2(a) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 4 ARRs defined in Step 2(a) that increase flows over this constraint until the constraint is relieved.

2(f): Test whether the ARRs identified in Step 2(e) are simultaneously feasible. If the set of ARRs defined in Step 2(e) is simultaneously feasible, proceed to Step 3.

2(g): Otherwise, calculate the pre- and post-contingency power flows associated with dispatching the system to honor the ARRs defined in Step 2(e).

2(h): Identify the constraint whose relief would require the largest proportionate reduction in all of the Stage 4 ARRs defined in Step 2(e) that increase flows over that constraint. Reduce proportionately on a per megawatt of constraint impact basis all Stage 4 ARRs defined in Step 2(e) that increase flows over this constraint until the constraint is relieved.

2(i) Repeat Steps 2(f) through 2(h) as necessary until a simultaneously feasible set of ARRs is obtained.

2(j) If as a result of the application of Steps 2(e) through 2(i) any of the constraints over which ARRs were reduced in Steps 2(e) through 2(i) is no longer binding, ARRs defined in Step 2(a) that have been reduced in Steps 2(e) through 2(i) and do not exacerbate any binding transmission constraint would be proportionately scaled up until a transmission constraint becomes binding.

Step 3. The remaining ARRs constitute the final allocation of ARRs. Holders of ARRs in this allocation shall be deemed ARR Holders.

III.C.6 Distribution of FTR Auction Revenues

Each ARR Holder shall be entitled to receive a monthly share of FTR Auction Revenues (excluding FTR Auction Revenues attributable to FTRs sold at auction by FTR Holders) from each FTR Auction. FTR Auction Revenues are determined by the value of each auctioned FTR as described in Section.7.3.6. FTR Auction Revenues shall not include the value of FTRs sold by FTR Holders, corresponding to its ARRs, whether or not such specific FTRs are actually sold. The determination of the FTRs awarded in each FTR Auction shall be subject to a simultaneous feasibility test in accordance with Section III.7 of Market Rule 1. The amount of feasible FTRs available in the FTR Auction (and the corresponding FTR Auction Revenues and payments to ARR Holders and Incremental ARR Holders) will vary depending on transmission system conditions as modeled. Incremental ARR Holders, described in Sections III.C.1and III.C.8, shall be entitled to receive a monthly share of the FTR Auction Revenues reflecting the incremental value of such transmission upgrade, as determined in accordance with Section III.C.8.

Following the distribution of FTR Auction Revenues for Incremental ARR awards, the ISO shall distribute the remaining monthly share of the FTR Auction Revenues. The distribution of FTR Auction Revenues is described below:

Step 1: For a specified destination Node, the amount of ARRs (quantified in megawatts) received in the final allocation of ARRs with specified origin Nodes or External Nodes and such destination Node shall be multiplied by the difference in the clearing prices determined in that FTR Auction for the same origin Nodes or External Nodes and such destination Node as the ARRs.

Step 2: A dollar value shall be allocated to each Load Zone. The dollar value to be allocated to each Load Zone shall be calculated by summing Step 1 over all of the Nodes in the Load Zone.

Step 3: A dollar value shall be allocated to each Asset Related Demand and Dispatchable Asset Related Demand within a Load Zone (excluding station service and pumps), which is settled at a Node and are not included in the Load Zone's Real-Time Load Obligation. The allocation is calculated using the dollar value of the ARRs for the specific Node associated with each Asset Related Demand and Dispatchable Asset Related Demand. The allocated dollar values are then subtracted from the dollar value previously allocated to the Load Zone in Step 2.

Step 4: The dollar value calculated in Step 2 for each Load Zone, as adjusted by any allocation to Asset Related Demands and Dispatchable Asset Related Demands in Step 3, shall be distributed to each ARR Holder in the Load Zone. The distribution shall honor Excepted Transactions and NEMA Contracts, as appropriate.

The dollar values calculated in Step 3 for each Asset Related Demand and Dispatchable Asset Related Demand in a Load Zone (excluding station service and pumps) shall be distributed to the ARR Holders associated with the Asset Related Demand and Dispatchable Asset Related Demand.

The remainder of the ARR Holder's distribution shall be in proportion to its Real-Time Load Obligation, excluding External Transaction sales, in the Load Zone at the time of the coincident peak for the New England Control Area for the month being settled less adjustments for Excepted Transactions and NEMA Contracts. Since the four-stage ARR Allocation process is not inherently revenue neutral, a proportional adjustment is applied to the auction revenue awards to distribute all available FTR Auction Revenues each month. The proportional adjustment is applied to ARRs awarded in the four-stage ARR Allocation process only.

III.C.7 Monthly ARR Settlement

ARR Holders shall receive a monthly share of FTR Auction Revenues, reflecting a monthly share of annual FTR revenues and the revenues from all monthly FTRs effective for the month being settled. Such monthly share shall reflect Incremental ARR awards, Excepted Transactions, NEMA Contracts, and the ARR Holder's Real-Time Load Obligation excluding External Transactions sales at the time of the coincident peak for the New England Control Area for the month being settled as described in Section III.C.6. The Incremental ARR awards used in the settlement of FTR Auction Revenues shall be prorated in proportion to the amount of incremental network capacity made available in the FTR Auction resulting in the FTR Auction Revenues to be distributed in accordance with Section III.C.8.

III.C.8 Incremental ARR Awards

An entity who pays for transmission upgrades which increase transfer capability on the New England Transmission System, making it possible for the ISO to award additional FTRs in the FTR Auction, shall be awarded Incremental ARRs. Transmission upgrades initially placed in-service on or after March 1, 1997 may qualify for Incremental ARR awards. The amount of any Incremental ARR award shall be specific MW quantities over one or more specific pairs of receipt and delivery points relevant to the upgrade and shall be determined once for each upgrade in accordance with Section III.C.8.1. The MW amount of the award shall reflect the amount of additional network capacity provided by the upgrade, prorated to reflect the entity's funding-share of the transmission system upgrade. An Incremental ARR award will have a value associated with each auction in which incremental network capacity is made available for the first time. The value will be determined by the sets of receipt and delivery points awarded for each Incremental ARR, the MW quantity awarded between each pair of receipt and delivery points, and the market-clearing prices for each pair of receipt and delivery points as determined by the auction. The determination of the sets of receipt and delivery points and the MW quantity associated with each pair, which comprise an Incremental ARR award, shall respect the order of service and study priority established through the Transmission, Markets and Services Tariff and ISO New England System Rules. Once determined, the subsequent valuation of an Incremental ARR depends only on the awarded set of receipt and delivery points and MW quantities, the amount of incremental network capacity made available in the FTR Auction, and on prices resulting from the associated FTR Auction. The Transmission, Markets and Services Tariff and ISO New England System Rules establish an order of both: (i) transmission upgrades eligible for Incremental ARR awards; and (ii) transmission upgrades paid for through the Pool PTF Rate. To the extent that transmission upgrades resulting in new transfer capability are paid for through the Pool PTF Rate, any ARRs associated with the sale of FTRs made possible by such upgrades, other than FTRs sold by FTR Holders, shall be allocated to Transmission Customers and Congestion Paying LSEs in the four-stage ARR Allocation process.

An entity who pays for transmission upgrades, initially placed in-service on or after March 1, 2003, and who requests Incremental ARRs, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, will be responsible for the cost of any study required to determine such Incremental ARRs.

Incremental ARRs shall be awarded to the entities funding the transmission upgrade at the later of the time the upgrade goes into service or when support payments begin, and shall continue for so long as the entities, or their successors, support the costs of the upgrade (either through up front support payments or periodic installments) or for the life of the upgrade (such as in the case where the upgrade is supplanted by a planned transmission system improvement published in the ISO's Regional System Plan prior to the upgrade's in-service date, but installed subsequently), if shorter.

All previously granted awards specifically associated with transmission upgrades shall be converted to Incremental ARR awards.

At the time an Incremental ARR award is made, the funding entity must provide documentation to indicate the share of the total transmission upgrade cost the entity is supporting, and whether that share of the transmission upgrade total cost is either fully funded, or funded by ongoing support payments. If funded by ongoing support payments, the documentation must indicate the schedule of remaining support payments. The Incremental ARR Holder must provide, upon request of the ISO, documents confirming that ongoing support payments are being made as required. If adequate confirmation is not provided within 30 days of the ISO request, the associated Incremental ARR Award will be terminated.

Incremental ARR Holders shall not be entitled to receive a share of any excess Congestion Revenue in the Congestion Revenue Fund, nor shall they be required to make payments into the Congestion Revenue Fund when the fund is insufficient to pay positive target allocations to all FTR Holders, as described for ARR Holders in Sections III.5.2.5 and III.5.2.6 of Market Rule 1.

If in any month the monthly FTR Auction Revenues plus the monthly share of annual FTR Auction Revenue for the relevant month are insufficient to provide the full value of the Incremental ARRs, as described in this Section, to the Incremental ARR Holders, the value of all Incremental ARRs for the month shall be prorated in proportion to their full value, such that the prorated value of all Incremental ARRs for the month equals the available monthly FTR Auction Revenues.

Incremental ARRs may be transferred to a Market Participant that is eligible to receive Incremental ARR payments. A request to transfer Incremental ARRs must be submitted by the existing holder at least 30 days prior to the requested transfer date. If the transmission upgrade associated with the Incremental ARR is funded by an ongoing stream of support payments, the transfer request must be accompanied by documentation indicating that the transferee has assumed the obligation to make the continuing support payments.

III.C.8.1 Determination of Incremental ARRS

The ISO will determine a baseline Incremental ARR award to an entity for an eligible transmission system upgrade that will reflect the additional cleared FTR amounts between receipt and delivery points made possible by the upgrade. The baseline award will comprise one or more pairs of receipt and delivery points relevant to the upgrade in the prevailing direction of real-time electrical power flows at the time the determination is performed.

Relevant pairs of receipt and delivery points shall include the complete set of all direct paths (receipt point and delivery point are directly linked by the upgraded facility) and sequential direct paths (receipt and delivery points are linked by a series of contiguous upgraded facilities). Where the upgrade includes several non-contiguous facilities, the complete set of all direct paths may include a number of individual direct paths that cannot be combined into a single sequential direct path. Where the transmission system upgrade increases the transfer capability of a transmission interface, the Incremental ARR shall be determined using receipt and delivery points comprised of the pairs of receipt and delivery points that define the interface.

The Incremental ARR determination is performed assuming all lines in service with no equipment outages and no reductions in equipment or interface ratings. The amounts of the baseline award on the relevant pairs of receipt and delivery points shall be determined by: (1) measuring the maximum FTR that can be cleared using he FTR auction clearing software with the transmission system upgrade included in the modeled network; (2) measuring the maximum FTR that can be cleared in the same manner with the upgrade excluded; (3) calculating the difference in total cleared FTRs over each relevant pair of receipt and delivery points. The increase in cleared FTRs over the relevant pairs of receipt and delivery points becomes the baseline award.

After receiving the baseline award, the entity requesting the Incremental ARR award may request the ISO to provide up to three additional Incremental ARR determination analyses. The ISO shall provide the entity with a list of all qualifying pairs of receipt and delivery points relevant to the upgrade that may be considered. The entity shall then identify for each determination analysis a specific set of pairs selected from the list of qualifying pairs of receipt and delivery points. In each determination analysis, the entity may adjust the MW amounts and bids to be used in the clearing calculations over the qualifying pairs to reflect the entity's preferences and priorities for specific receipt and delivery point pairs in the Incremental ARR award. The ISO shall repeat the award determination analysis for the requested set of relevant pairs of receipt and delivery points, and shall provide the resulting MW awards to the entity. The entity shall then select the results of either the baseline award or any one of the determination analysis awards to become the final Incremental ARR award.

EXHIBIT 1

NEMA CONTRACTS

NEMA Load-Serving Entity	NEMA Contract Entitlements (Stated by percentages in the case of unit entitlement held on percentage basis, and by megawatts when contract states entitlement in megawatts.)
Danvers	1. Millstone 3 (0.263%) 2. Seabrook (1.112%) 3. Stony Brook Combined Cycle (8.457%) 4. Stony Brook 2A (11.555%) 5. Stony Brook 2B (11.555%) 6. Vermont Yankee (1.080 MW) 7. Hydro Quebec (2.930 MW (winter)) 8. NYPA (2.440 MW)
Georgetown	1. Millstone 3 (0.021%) 2. Seabrook (0.096%) 3. Stony Brook Combined Cycle (0.736%) 4. Stony Brook 2A (1.014%) 5. Stony Brook 2B (1.014%) 6. Vermont Yankee (0.144 MW) 7. System Power (Select Energy) (2.0 MW) 8. Hydro Quebec (0.280 MW (winter)) 9. NYPA (0.620 MW)
Ipswich	1. Millstone 3 (0.061%) 2. Seabrook (0.107%) 3. Stony Brook Combined Cycle (0.293%) 4. Vermont Yankee (0.522 MW) 5. NYPA (1.350 MW)

Marblehead	1. Millstone 3 (0.154%) 2. Seabrook (0.135%) 3. Stony Brook Combined Cycle (2.684%) 4. Stony Brook 2A (1.598%) 5. Stony Brook 2B (1.598%) 6. Wyman 4 (0.279%) 7. Vermont Yankee (0.655 MW) 8. Hydro Quebec (1.040 MW (winter)) 9. NYPA (2.140 MW)
Middleton	1. Millstone 3 (.044%) 2. Seabrook (0.328%) 3. Stony Brook Combined Cycle (0.878%) 4. Stony Brook 2A (1.892%) 5. Stony Brook 2B (1.892%) 6. Wyman 4 (0.101%) 7. Vermont Yankee (0.213%) 8. System Power (NU 10.000 MW, PGET 0.500 MW) 9. Hydro Quebec (0.580 MW (winter)) 10. NYPA (0.600 MW)
Peabody	1. Millstone 3 (0.297%) 2. Seabrook (1.130%) 3. Stony Brook Combined Cycle (13.052%) 4. Vermont Yankee (1.693 MW) 5. Hydro Quebec (3.480 MW (winter)) 6. NYPA (4.860 MW)
Reading	1. Millstone 3 (0.404%) 2. Seabrook (0.635%) 3. Stony Brook Combined Cycle (14.453%) 4. Stony Brook 2A (19.516%)

	5. Stony Brook 2B (19.516%)
	6. System Power (NU) (15 MW)
	7. Hydro Quebec (5.710 MW (winter))
Wakefield	1. Millstone 3 (0.206%)
	2. Seabrook (0.387%)
	3. Stony Brook (3.993%)
	4. Stony Brook 2A (6.379%)
	5. Stony Brook 2B (6.379%)
	6. Wyman 4 (0.440%)
	7. Vermont Yankee (0.885 MW)
	8. Hydro Quebec (1.520 MW (winter))
	9. NYPA (2.230 MW)
Concord	1. Hydro Quebec (0.890 MW (winter))
Groveland	1. System Power (NU) (6.100 MW)
	2. NYPA (0.510 MW)
Merrimac	1. System Power (NU) (4.900 MW)
	2. NYPA (0.520 MW)
Rowley	1. System Power (NU) (6.700 MW)
	2. Hydro Quebec (0.200 MW (winter))
	3. NYPA (0.510 MW)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.,	**)**	
New England Power Pool, and	**)**	**Docket No. ER11- ____-000**
Participating Transmission	**)**	
Owners Administrative Committee	**)**	

TESTIMONY OF JONATHAN B. LOWELL

INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is Jonathan B. Lowell. I am employed by ISO New England Inc. (the "ISO"), where I am a Principal Analyst in the Market Development Department. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND RELEVANT PROFESSIONAL EXPERIENCE.

A: I am currently a Principal Analyst in the Market Development group at the ISO, where I have been employed since January 2006, with responsibilities for identifying design improvements in New England's electricity markets, and drafting appropriate market rules and manuals to implement those improvements. Prior to joining the ISO, I have had wide-ranging experience in the electricity industry, including four years with TransEnergie US, an independent transmission development firm, three years in the energy practice at the economics consulting firm PHB Hagler Bailly where I specialized in the economic analysis of investment opportunities in competitive electricity markets, and 18 years with the New England Electric System with responsibilities for resource planning and portfolio management. I have testified before state regulatory commissions and siting councils on issues including resource economics, integrated resource planning and portfolio design and optimization. I provided testimony to the Federal Energy Regulatory Commission ("Commission") supporting the ISO's initial proposal to conduct a pilot program to evaluate the ability of alternative technologies to provide regulation service in New England. More recently, I provided testimony to the Commission supporting revisions to the Forward Reserve Market rules relating to the implementation of the Forward Capacity Market (Docket No. ER09-1766-000), and revisions to energy market rules that give practical effect in the energy market to capacity export offers that clear in the Forward Capacity Auction (Docket No. ER09-1408-000).

I hold a Sc.B. in Applied Mathematics from Brown University and an MBA from Worcester Polytechnic Institute.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of this testimony is to explain: (i) the Financial Transmission Right market design and tariff changes (the "FTR Enhancements") to the ISO New

England Inc. Transmission, Markets and Services Tariff (the " ISO Tariff")[1] developed through the New England Power Pool ("NEPOOL") stakeholder process, and; (ii) why the changes are reasonable, economically sound and consistent with New England's existing electricity market design.

Q: HOW IS THIS TESTIMONY ORGANIZED?

A: My testimony is organized in four parts:

- Part I - An overview of the existing system of Financial Transmission Rights ("FTRs") and Auction Revenue Rights ("ARRs"), as reflected in the Tariff (Section I), and background on the historical nature of transmission services and transmission ratemaking that has been used in New England.
- Part II – Discussion of the two major areas affected by the FTR Enhancements. These areas are the introduction of a two-round structure in the auction of annual FTRs, the introduction of monthly balancing (i.e. reconfiguration) auctions to supplement the existing prompt-month auctions of monthly FTRs.
- Part III – Discussion of the replacement of Qualified Upgrade Awards ("QUAs") by Incremental ARRs ("IARRs").

[1] Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the ISO Tariff.

PART I.

NEW ENGLAND'S EXISTING TRANSMISSION SERVICE STRUCTURE AND FTR/ARR STRUCTURE

Q: PLEASE EXPLAIN THE EXISTING TRANSMISSION SERVICE STRUCTURE IN NEW ENGLAND.

A: The operational scheduling of the New England Transmission System is based on the economic clearing of supply and demand through participant submitted Supply Offers and Demand Bids, as well as the known characteristics and constraints of the New England Transmission System. Transmission Customers pay for, and receive, network transmission service ("Regional Network Service") that entitles them to the use of a share of the entire New England Transmission System, and neither generation nor load needs to actually schedule transmission service.

The commitment of resources for the next Operating Day is initially conducted through the Day-Ahead Energy Market. The Day-Ahead Energy Market produces Locational Marginal Prices ("LMPs") at every injection and withdrawal node on the system. Generators are paid the LMP at their location and loads pay the LMP (generally at load zone weighted average) at their location. LMP differences between locations are indications of either congestion costs or marginal losses.

The congestion cost components of LMPs are the result of the security-constrained economic dispatch of energy within the physical limits of the transmission system. When the New England Transmission System is constrained and cannot move additional power across a constraint, higher-priced generation is dispatched up on the "import-constrained side" of the constraint to ensure that the energy balance is maintained. In this situation, the LMP on the import-constrained side would be higher than the LMP on the "export-constrained side" because more expensive generation must be dispatched to meet load on the import-constrained side. The higher LMP reveals the increased marginal cost of consuming energy in the presence of the transmission constraint. Ignoring marginal losses, the difference between LMPs multiplied by consumption (MW) equals the congestion cost.

Q: PLEASE EXPLAIN THE EXISTING SYSTEM OF FTRS IN NEW ENGLAND.

A: An FTR is a financial instrument that entitles the holder to receive compensation equal to Congestion Costs that arise between two locations when there are binding transmission constraints in the Day-Ahead Energy Market between those locations. FTRs can be used by Market Participants to hedge their exposure to LMP congestion cost volatility. Each FTR is unidirectional and is defined in megawatts from a point-of-receipt (where the power is injected onto the New England Transmission System) to a point-of-delivery (where the power is withdrawn from the New England Transmission System). The cash flow of an FTR is determined by the difference between the congestion component of the day-ahead LMP at the point-of-receipt and the point-of-delivery. Because the

FTR is an obligation, the cash flow can be positive or negative.

The ISO's existing market design requires participants to bid in an auction to acquire FTRs and the right to future day-ahead transmission congestion revenues ("TCRs"). By acquiring an FTR, a Market Participant offsets congestion cost exposure in the Day-Ahead Energy Market on a given path (source, sink, amount) with the payout (or charge) from the FTR, and in so doing hedges congestion costs on that path. In other words, the Market Participant may choose to pay a fixed price for an FTR in exchange for eliminating its exposure to the potential volatility of congestion costs in the energy market.

Q: WHAT ARE THE OTHER RELEVANT ASPECTS OF THE EXISTING CONGESTION MANAGEMENT MARKET DESIGN?

A: In addition to FTRs, the current market design also features a complementary congestion management mechanism, ARRs. As stated previously, Market Participants currently acquire FTRs by bidding into the FTR auctions. Winning bidders pay the appropriate clearing price for each of their successful bids. The auction revenues received from the successful bidders are distributed to Congestion Paying LSEs as ARRs and entities funding transmission upgrades through QUAs. The amount of ARRs allocated to each participant depends upon the Load Zone in which the participant's real-time load is located, the participant's share of the real-time load at the time of the system peak, and the value of transmission paths from each generator in the control area to the respective Load Zone as determined by the FTR auction results. Congestion Paying LSEs may choose to use the revenues they receive from ARRs to help pay the costs of acquiring FTRs, or they may choose to keep the revenues they receive from ARRs without seeking to acquire any FTRs.

PART II.

CHANGES TO THE ANNUAL AND MONTHLY FTR AUCTION DESIGN

Q: PLEASE PROVIDE AN OVERVIEW OF THE FTR ENHANCEMENTS.

A: The FTR Enhancements build on the existing annual and monthly FTR markets in New England, by adopting a two-round auction design for annual FTRs, and adding monthly reconfiguration auctions[2] in which FTR positions held in forward months can be modified.

In the existing annual auction, 50% of the network capacity is made available in an auction for the on-peak period and 50% of the network capacity is made available in a separate auction for the off-peak period. Each auction is conducted in a single round. Under the proposed enhancements, 25% of the network capacity would be made available in the first round of separate on-peak and off-peak annual auctions. The results of these auctions would be published prior to the start of a second and final round. In the second round, an incremental 25% of

[2] The reconfiguration auctions have also become known as "balancing" auction, primarily because of the design inspiration provided by the "Balance of Planning Period" FTR auctions provided in PJM.

the network would be made available for a cumulative total of 50% of the network available in the separate on-peak and off-peak annual auctions. FTRs acquired in the first round would be accounted for during the second round to ensure the 50% available network capacity is not oversold. Market participants that acquired FTRs in the first round would be able to sell those FTRs in the second round if they so desire.

In the existing FTR market, on-peak and off-peak monthly FTRs are auctioned only once for each month in monthly auctions, when the month to be auctioned is the prompt month (*i.e.*, just prior to the start of the month to be auctioned). Currently, the network capacity remaining after the annual auction is made available for sale in the prompt month auctions. In the enhanced design, every remaining month in the calendar year would be auctioned every month. No additional network capacity beyond the capacity offered in the annual auctions would be available in the non-prompt month auctions. The non-prompt month auctions allow network capacity previously sold in the annual auctions to be reconfigured amongst participants based on their changing requirements and expectations for the market, as well as the purchase of any unsold portion of the 50% of network capacity made available in the annual auction. Auction participants would be able to expand, liquidate or otherwise modify their existing FTR portfolios both by trading via the auction with other FTR participants, and by acquiring previously available but unsold network capacity.

Under the enhanced FTR market design, the on-peak and off-peak prompt month auctions would remain essentially unchanged from the current design. The remaining network capacity would be made available. Planned transmission outages during the month and all previously sold FTRs effective during the month would be accounted for to ensure the network is not oversold.

Q. WHAT BENEFITS DO THESE ENHANCEMENTS PROVIDE TO THE EXISTING FTR MARKET?

A. There are two principal benefits, which then make possible a number of secondary benefits. The principal benefits are: (1) greatly increased FTR liquidity and (2) enhanced price discovery. In the current design, an FTR purchased in the annual auction that becomes no longer useful after a period of several months, perhaps due to reduced load obligations, new power supply arrangements or because congestion patterns have changed, can only be liquidated one month at a time in the prompt month auctions. Similarly, a Load Serving Entity ("LSE") that takes on new long-term load obligations, say for 6-12 months, can only implement an FTR congestion risk hedging strategy a single month at a time. Under the enhanced design, FTR positions for the entire remainder of the year would be tradeable every month.

There is some evidence that the enhanced FTR market design would lead to increased FTR transaction volume. During NEPOOL stakeholder discussions that initiated the ISO's design effort, a Market Participant presented historical information illustrating significant increases in PJM FTR volumes traded between the periods before and after the implementation of the "Balance of Planning Period" ("BoPP") FTR auctions in 2006.[3] The New England FTR Enhancements bear important similarities to the BoPP design in PJM, particularly with regard to improved liquidity. Increased trading volumes in New England are certainly a potential positive outcome.

Enhanced price discovery is the second principal benefit. Adding a second round to the annual auction, with significant new capacity made available in each round, and with clearing prices published at the end of each round, would give participants an important additional source of price information that is simply unavailable in the current design. The monthly reconfiguration auctions would, for the first time, allow participants and the ISO to estimate a forward monthly price curve that exposes the impacts of factors that change over the course of the year, such as seasonal congestion, mid-year generation additions, and transmission improvements.

Together, increased liquidity and improved price discovery enhance the ability to manage the market and credit risks associated with the FTR market.

[3] *See* Presentation of Mr. Bruce Bleiweis at the July 2010 NEPOOL Markets Committee meeting, available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2010/jul12142010/a7_dc_energy_presentation_07_12_10.pdf.

Q: WHAT OTHER SECONDARY BENEFITS ARE PROVIDED BY A MULTIPLE ROUND AUCTION?

A: One of the ISO's important objectives for any ISO-administered market is the efficient allocation of resources. The auction design on which the FTR market is based can help or hinder that objective. In a perfectly efficient market, all buyers and sellers would obtain a portfolio representing exactly the quantities of FTR paths desired at the final market clearing prices. No buyers would desire additional quantities at the final clearing prices, nor would they be interested in selling any part of their portfolio at the clearing price.

In a single-round auction, this outcome is difficult to achieve. Little or no market price information is available, and auction participants must rely on their own estimates of future congestion to infer a market value. Access to the limited information that is available may be asymmetric because smaller participants may not have the staff or analytical expertise available to extract useful market intelligence from the masked participant bid data and cleared FTR results published by the ISO. Conceptually, multi-round auction designs provide a means to address this concern. In the extreme, rounds can be allowed to continue indefinitely until a round is completed in which no bids or offers clear. At that point, an efficient allocation of network capacity has been achieved and the auction is terminated. Prices at the end of each round would eventually converge towards a market outcome representing an efficient FTR allocation.

Auctions for complementary goods with sub-additive valuations[4] subject bidders to the "Exposure Problem." For example, suppose a participant can adequately hedge his congestion risk by acquiring a 10 MW FTR across the Connecticut Import Interface, and there are numerous FTR paths that source outside of Connecticut and sink inside the import interface. Any path provides the desired hedge, but if the participant bids for only a single path, and the offer does not clear, the participant would be unhedged. To avoid this risk, the participant can submit two separate bids, each for a different 10 MW path across the import interface, but this would expose the participant to the risk of having both bids clear for a total of 20 MW across the interface. If this happens, the participant would overpay for the cleared portfolio of FTRs. In a single-round auction, participants may be forced to manage this exposure by underbidding for one or both goods, leading to depressed prices. A multiple round auction allows bidders to iteratively acquire their desired portfolios with reduced risk, without the additional complexity of "package bidding,"[5] an approach used in radio frequency spectrum auctions conducted by the Federal Communications Commission.

Q: WHAT ARE THE DISADVANTAGES OR POTENTIAL WEAKNESSES OF MULTI-ROUND AUCTIONS THAT MUST BE CONSIDERED IN THE MARKET DESIGN?

[4] For example, Good A is independently valued by the participant at X, and Good B is independently valued at Y. A sub-additive valuation is present where the value of holding both Goods A and B together is less than X plus Y. FTRs over different but related paths have characteristics of complementary goods.

[5] Package bidding allows participants to submit offers for combinations of goods, but can be impractical when a large number of complementary goods are included in the auction. With more than 900 FTR source and sink locations in New England, the combinatorial possibilities make package bidding in the FTR market impractical, if not infeasible.

A: Participation in each additional round incurs additional costs. During NEPOOL stakeholder discussions, participants indicated that each FTR auction requires a substantial investment of time and analysis, and that similar efforts would be required for each additional round. The cost of participating in a large number of rounds was perceived to outweigh the marginal increase in benefits from additional rounds. Further, additional time is required to administer additional auction rounds. Each additional round that must be completed prior to the start of a new year requires that the first round of the annual auction start earlier. Greater lead time means greater uncertainty for participants as they develop their bids. For these and possibly other reasons, NEPOOL participants expressed no interest during stakeholder discussions in conducting more than two annual auction rounds.

Multi-round and continuous[6] auctions are sometimes vulnerable to "sniping," where an interested bidder remains on the sidelines during most of the auction, hoping to avoid stimulating competition from other bidders that would drive the price up, and then submitting a low winning bid in the final moments of the auction. An auction design that permits or encourages sniping strategies can suppress prices to levels below where an efficient market would clear. The proposed FTR market design attempts to avoid sniping behavior by imposing limits on network capacity made available in each of the annual rounds.

[6] Internet auctions, such as those operated by eBay, with a defined auction closing time are examples of continuous auctions. Improved bids may be submitted at any time, with no requirement for active participation in the auction prior to the final seconds before closing.

Participants looking to assemble large FTR portfolios into congested areas would have strong incentives to participate fully and actively in both rounds or risk being unable to fulfill their hedging requirements.

Finally, multi-round auctions with little change in market conditions between rounds create an opportunity for signaling and collusion[7] amongst bidders, This, in turn, can lead to suppressed clearing prices. Information published at the end of each round can be used by clever bidders as a communication channel to all other auction participants, even when bidder identities are disguised and effectively anonymous.

Consider, for example, a hypothetical FTR auction using an ascending auction design of the type that has been used in past frequency spectrum auctions. The auction is conducted in rounds, and bidders submit separate offers for each desired FTR path. A new bid for a specific allocation must exceed the bidder's previous offer by at least 10 percent. The auction terminates when no bidder wishes to submit a higher offer on any path. Suppose Bidder 1 desires FTRs on path XY and submits a initial offer in round 1. Given the ascending nature of the auction, initial round offers would generally start low. Bidder 1 observes at the end of round 1 that Bidder 2 was bidding for two different paths, ST and XY. In round 2, Bidder 1 might attempt to dissuade Bidder 2 from further competition for path XY by submitting an aggressively higher "punishment" offer for path ST, even though Bidder 1 does not ultimately wish to acquire path ST. If Bidder 1

[7] *See* Klemperer, Auctions: Theory and Practice, Princeton University Press, 2004, at 104-105.

observes Bidder 2 cooperates in subsequent rounds by no longer submitting competing offers for path XY, Bidder 1 reciprocates by discontinuing the submission of "punishment" offers in future rounds for path ST, and the auction terminates quickly. Both parties come out ahead (less competition for their desired paths), with no need for direct communication, or even specific knowledge of whom the potential competitor might be.[8]

Clearly, the opportunity for effective signaling is greater when there are a large number of rounds, and when a large quantity of detailed information described submitted bids and cleared results is published. The proposed auction design addresses both of these points. The FTR annual auction would provide only two rounds, limiting the potential for signaling. Second, the information published at the end of the first round would be restricted to include only the auction clearing prices, and awarded FTRs (path and quantity) without ownership information. No information on bids submitted would be released, and no information on paths cleared by individual bidders would be released until after the second round is completed. Participants would have available all the information reasonably required to prepare bids for the second round, that is, the market prices from first round and the available unsold network capacity, but would not have detailed data that could facilitate signaling.

[8] Note that in actual practice, the simultaneous manner in which FTR auctions clear and in which nodal clearing prices are established means prices for separate paths may not be independent, as depicted in this example, and may complicate attempts at signaling. It is nevertheless appropriate to evaluate the FTR auction design to ensure signaling opportunities are minimized.

At the conclusion of the annual auction following the second round, the ISO would release the same information that is currently released at the conclusion of the single-round annual auction.

Q: CONSIDERING ALL THESE FACTORS, PLEASE SUMMARIZE THE RECOMMENDED ANNUAL AUCTION DESIGN.

A: The FTR annual auction would have two rounds. 25% of on-peak network capacity would be available in the first round, and an additional 25% of on-peak network capacity would be available in the second round. The corresponding quantities of off-peak network capacity would be available, as well. The first round would provide initial market-derived prices and cleared FTR quantities by path that can be used by the market to inform second round bids and offers. Price changes in the second round would reflect movement towards the "true" market value of the FTRs that would emerge if auction rounds stopped only when no further bids and offers clear. Prices resulting from the second round would provide a better estimate of the actual market value than what the current single-round design provides.

A two-round annual auction with the publication of only limited results between the rounds would accomplish the great majority of the benefits of multi-round auctions suggested by theory, while limiting both the transaction costs imposed on participants and the opportunities for non-competitive behavior that could arise with a larger number of rounds. Two rounds would improve the convergence of auction prices towards the efficient outcome that would arise in an ideal competitive market. Better market price estimates, in turn, support more accurate assessments of risk and the related financial assurance requirements.

Q: HOW WILL YOU BE ABLE TO DETERMINE IF THE ENHANCED ANNUAL AUCTION DESIGN HAS ACHIEVED AN EFFICIENT MARKET ALLOCATION OF FTRS?

A: If, after several two-round annual FTR auctions have been completed, a pattern of large price changes between the first and second rounds is observed, it would be an indication that two rounds may be insufficient for the market to converge to an efficient allocation. In such a case, it would be appropriate to consider if one or more additional rounds would improve the operation of the annual market. However, small price changes would likely be an indication that any efficiency improvements gained from additional rounds would not justify the associated transaction costs.

Q: PLEASE EXPLAIN ANY CHANGES IN THE DETERMINATION AND ALLOCATION OF AUCTION REVENUE RIGHTS NECESSITATED BY THE ADDITIONAL ANNUAL AND MONTHLY FTR AUCTIONS INCORPORATED IN THE ENHANCED MARKET DESIGN.

A: The New England market design utilizes ARRs to distribute the proceeds from the sale of FTRs to Congestion Paying LSEs. The amount of ARRs allocated to each participant depends upon the Load Zone in which the participant's real-time load is located, the participant's share of the real-time load at the time of the system peak, and the value of transmission paths from each generator in the region to the respective Load Zone as determined by the FTR auction results. As noted above, Congestion Paying LSEs may choose to use the revenues they receive from ARRs to help pay the costs of acquiring FTRs, or they may choose to keep the revenues they receive from ARRs without seeking to acquire any FTRs.

In the FTR Enhancements, the ARR methodology is being revised in minor ways to recognize the additional annual auction rounds and the monthly reconfiguration auctions. The auction revenues associated with each annual auction round would be allocated to Congestion Paying LSEs based on the specific auction prices resulting from each round. This is completely consistent with the current methodology.

The monthly reconfiguration auctions (other than the prompt month auctions) are a new element in the FTR market design and consequently, the current ARR methodology does not contemplate this element. The current ARR methodology utilizes a four-stage process. Within each stage, the methodology requires monthly auction prices and monthly peak loads,[9] and uses an iterative algorithm that typically requires significant administrative effort to ensure successful completion. Considering the large increase in the number of monthly FTR

[9] More specifically, the ARR calculation requires each Congestion Paying LSE's Real-Time Load Obligation at the time of the monthly coincident peak demand for the New England Control Area. *See* Market Rule 1, Section III.C.7.

auctions, the ISO has determined that it is administratively infeasible to conduct the current ARR process for each and every monthly auction.[10]

Further, no new network capacity is made available in the reconfiguration auctions. The net auction revenues to be distributed by the ARR process would derive primarily from purchases of previously unsold capacity and counterflow bids.[11] Transactions that represent transfers of previously sold capacity from one participant to another would not produce any net auction revenue for allocation to Congestion Paying LSEs, because the revenue from those transactions accrues to the FTR seller. Conversely, the prompt month auctions make available the remaining unsold network capacity of the system, sales of which would lead to net auction revenues for allocation through the ARR process.

Considering the infeasibility of conducting the current ARR process for every monthly auction, and the likelihood that the majority of the net auction revenues associated with June, for example, would derive from the June prompt month auction, the new ARR design accumulates all of the net auction revenues from all of the June reconfiguration auctions plus the June prompt month auction. The accumulated June net auction revenue is then allocated to Congestion Paying LSEs using the prices from the June prompt month auction and the existing ARR

[10] For the month of January, there would be 24 separate monthly auctions: two prompt month auctions (on-peak and off-peak) and 22 reconfiguration auctions (February-December, on-peak and off-peak).

[11] A counterflow bid, in this context, is an offer to purchase a FTR on a path that may already be partly or fully subscribed, but in the opposite direction.

methodology. The prompt month prices are the most current prices for the month when the ARR allocation is performed, and represent the market's expectation for congestion in the Day-Ahead Energy Market. The approach reasonably balances the intent and operation of the existing monthly ARR methodology, which is to distribute FTR auction revenues back to those who pay congestion, against the practical realities of administering the FTR market.

PART III.

REPLACING QUALIFIED UPGRADE AWARDS WITH INCREMENTAL ARRS

Q: PLEASE EXPLAIN THE EXISTING SYSTEM OF QUAS IN NEW ENGLAND.

A: The existing QUA process is conducted at the end of each FTR auction to measure the change in the dollar value of awarded FTRs attributable to specific transmission upgrades funded by specifically identified entities. These include only Elective Transmission Upgrades and Generator Interconnection Related Upgrades, and not upgrades paid for through the Pool PTF and Pool RNS Transmission Rates.

The existing QUA process is time-consuming to administer and the determination of the actual monetary value of a specific QUA in any particular FTR auction is not particularly transparent for the QUA holders. After an FTR auction is completed, the QUA process repeats the auction starting with a network topology that initially excludes all of the transmission upgrades, and then adds each upgrade back into the topology in a sequential manner. The increased value of the auction arising from the inclusion of each sequential upgrade becomes the value of the QUA award for the associated upgrade. As the number of QUAs increases, the number of the sequential auction reruns, and the complexity of the award determination increases. Indeed, in the Commission's 2002 order accepting New England's "standard market design" proposal,[12] the Commission recognized that the QUA process was intended to be replaced by a permanent process.[13] Also, as anticipated in the SMD Order, the rules designed to implement Long-Term Transmission Rights (known to New England stakeholders as Long-term FTRs, or "LFTRs"), submitted by ISO New England and approved by the Commission in 2008,[14] created a new process to replace QUAs with IARR awards for entities funding transmission upgrades.

Q: **ARE IARRS CURRENTLY IN EFFECT IN NEW ENGLAND?**

A: No, the rules have been approved, but have not been made effective pending the

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[12] *See New England Power Pool and ISO New England*, 100 FERC ¶ 61,287 (2002) ("SMD Order"). The SMD Order accepted in part and modified in part the proposal jointly filed by the ISO and NEPOOL on July 15, 2002 to replace the design of the then-existing NEPOOL markets with Market Rule 1, commonly referred to as "Standard Market Design", a. *See New England Power Pool and ISO New England*, NEPOOL Standard Market Design, Docket No. ER02-2330 (July 15, 2002).

[13] *See* SMD Order at P 15 ("The QUA process is a temporary measure which ISO-NE anticipates replacing.").

[14] In October 2008, the Commission granted final approval for market rules to implement long-term transmission rights in New England. *See New England Power Pool and ISO New England*, 125 FERC ¶ 61,069 (2008) ("LFTR Order"). Those rules, which encompassed the replacement of QUAs with IARRs, have not yet gone into effect, pending the resolution with NEPOOL stakeholders of market and credit risk concerns.

development of necessary software infrastructure that was planned as part of comprehensive software development and implementation effort to support LFTRs. Although preliminary LFTR development commenced in 2008, LFTR-related market and credit risk issues must be successfully resolved before development and implementation of the LTTR software infrastructure can be completed.

The development work necessary to support the FTR auction enhancements presents an opportunity to create the software infrastructure allowing QUAs to be permanently replaced by IARRs.

Q: WHAT ARE THE ADVANTAGES OF IMPLEMENTING IARRS AS PART OF THE FTR ENHANCEMENTS?

A: There are three advantages. First, IARRs provide transparency to the award holder. The only additional information a participant requires to determine the value of an IARR is the nodal pricing from the appropriate FTR auction. This information is published at the conclusion of every auction. With the existing QUA process, it is simply not possible for a market participant to calculate the value of a QUA. The calculation requires rerunning the auction, which necessarily requires having all of the submitted bid information. Only the ISO has all the submitted bids, and therefore, only the ISO is able to determine the value of a QUA for each auction.

Second, in the time since the IARR rules were approved in 2008, several stakeholders have requested "early" implementation of IARRs. This is the first opportunity to meet that request, and is likely to be the only opportunity until LFTR development resumes.

Third, the IARR process does not require the numerous sequential iterations required for each FTR auction. This greatly simplifies the time required to administer the FTR market. With the additional annual auction rounds and monthly reconfiguration auctions, it would simply not be feasible to continue with the existing QUA process. For all practical purposes, replacing QUAs with IARRs is a step required to make it possible for the ISO to administer the additional auctions required by the FTR Enhancements.

Q: HOW WILL IARRS BE AWARDED?

A: As described in Mr. Marc Montalvo's testimony submitted in Docket No. ER07-476-000 in January 2007,[15] the ISO would evaluate transmission upgrades and would make an initial determination of the incremental amount of FTRs made possible by the upgrade between defined receipt and delivery points related to the upgraded transmission elements. The entity funding the upgrade would have the opportunity, through an iterative determination process, to modify certain study parameters and to determine its specific IARR award based on the expected future value of the award. At the conclusion of the determination process, the exact

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[15] *See ISO New England Inc. and New England Power Pool*, Docket Nos. ER07-476-000 *et al.* (January 29, 2007).

amounts and receipt and delivery points are finalized. These would not change from auction to auction, although the dollar value of the IARR award in each auction would depend on the specific path clearing prices produced by the auction.

Q: HOW WILL EXISTING QUAS BE TREATED?

A: Each of the existing QUAs would be converted into IARRs following the process just described. Each conversion is a one-time process.

Q: ARE ANY REFINEMENTS OR MODIFICATIONS TO THE RULES APPROVED IN 2008 BEING PROPOSED AS PART OF THIS FILING?

A: There are no changes proposed in how IARRs are determined, or in the fundamental manner in which they provide financial compensation to entities that fund upgrades to the transmission system. There are several modifications included for the purpose of making explicit some of the rights and obligations of IARR Holders that were not explicit in the 2008 rules. Specifically: (a) the rules clarify that if an IARR is funded by ongoing support payments, the holder of the IARRs must provide, on request of the ISO, documents that confirm that ongoing support payments are being made as required, and; (b) the holder of an IARR may transfer ownership to another Market Participant that is eligible to receive IARR payments, and that transferee would assume the obligation to make any required ongoing support payments.

The new rules clarify that IARRs only receive compensation in connection with auctions in which additional network capacity is made available beyond what was made available in previous auctions for that year due to the transmission upgrade associated with the IARR. This implies that there would be no IARR awards for the monthly reconfiguration auctions. Awards would be paid in association with both annual auction rounds and with all prompt month auctions. IARRs provide payment to the holder whenever the value based on the price difference between the sink nodes and the source nodes is positive, but unlike an FTR, does not require the holder to make a payment when the value is negative. Limiting the award associated with a specific auction by the fraction of network capacity made available in that auction is necessary to ensure that a transmission upgrade would never be compensated, in effect, for more than 100% of the upgrade capacity it provides.

Finally, the IARR rules approved by the Commission in 2008 as part of the LTTR rules provide the holder with the right to convert an IARR into an Incremental LFTR ("ILFTR").[16] However, this conversion is not being provided for as part of these proposed FTR Enhancements. Providing support for ILFTRs would require significant enhancements to the FTR auction engine software, would significantly increase the scope of the FTR Enhancements, and would require significantly greater time, expense, and efforts. Implementation of ILFTRs will likely continue

[16] An ILFTR is equivalent to an FTR that can only have a positive value, sometimes referred to as an "option FTR". Where IARRs provide the holder with compensation that is a share of auction revenues based on FTR auction prices, ILFTRs provide compensation to the holder based on nodal price differences (*i.e*. congestion) in the Day-Ahead Energy Market.

to be deferred until such time as the ISO is able to move forward with implementation of the full LFTR market design and associated software infrastructure, as previously approved.

Q: PLEASE DESCRIBE THE DEVELOPMENT EFFORT REQUIRED TO SUPPORT THE FTR ENHANCEMENTS.

A: The FTR Enhancements require changes to vendor-supported software systems used to administer the FTR auctions. The vendor already has reviewed the proposed design modifications and estimated the level of effort required to develop the necessary changes to the FTR software systems.

Additional changes are required to the software systems that handle market settlements (including FTRs, ARRs and IARRs) and financial assurance. These are supported by internal ISO resources. Preliminary planning for these changes has begun, primarily to ensure that the ISO can make efficient use of the internal development resources that must also support the FCM re-design initiative and the Order No. 745 demand response compensation initiative that will be ongoing during 2011 and 2012.

The ISO's initial planning effort has determined that IARRs can be implemented for the annual FTR auctions that will be conducted in the November 2011 timeframe for FTRs effective for the 2012 calendar year. There are good reasons to meet this implementation date: (a) Market Participants have previously requested early IARR implementation, and; (b) there are significant, permanent administrative efficiencies in the ongoing use of ISO resources that are gained by replacing QUAs with IARRs. The conversion must be done for all of the existing QUAs and therefore, would require several months to complete. The original rules governing the conversion process were accepted by the Commission in the 2008 LFTR Order and are not being modified by the FTR Enhancements. The conversion effort must be started now in order to be completed in time to support implementation for the 2012 calendar year. To that end, the ISO already has begun working with QUA holders to begin the process that would lead to conversion of QUAs to IARRs.

The ISO's initial effort to estimate the amount of work required and to plan for the availability of the specific resources needed to develop and test the systems that support the FTR Enhancements has determined that it is not possible to implement multiple rounds for the annual auction for calendar year 2012 or monthly reconfiguration auctions for every month in 2012. However, the ISO anticipates that annual auction rounds can be implemented for FTRs that will be effective for calendar year 2013.

Also, it may be possible to implement monthly reconfiguration auctions mid-year in 2012. The ISO is still evaluating this option. A mid-year implementation of monthly reconfiguration auctions should have no adverse impacts on market participants, as participation in a reconfiguration auction is purely voluntary.

Those who desire to acquire FTRs month by month during the year may use the prompt month auctions which will operate in exactly the same manner as the current monthly FTR auctions. The ISO is requesting that the FTR auction changes be allowed to become effective upon two weeks' notice rather than on a fixed effective date. This would allow for early implementation in case such early implementation proves to be feasible.

Q: **DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes, this concludes my testimony.

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

Executed on 5-13-11.

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