



April 21, 2010

VIA HAND DELIVERY

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

Re: Filing of ISO New England Inc. and New England Power Pool Filing in Response to Commission Order on ISO New England Inc.'s Order No. 719 Compliance Filing; Docket No. ER09-1051-_____

Dear Secretary Bose:

Pursuant to Rule 1907 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission" or "FERC"),¹ 18 C.F.R. § 385.1907 (2010), and the Commission's January 21, 2010 order in this proceeding,² ISO New England Inc. (the "ISO") and the New England Power Pool Participants Committee ("NEPOOL") (together, the "Filing Parties") hereby submit an original and five copies of this filing in response to the compliance requirements set forth in the January 21 Order, including revised tariff sheets to effect modifications to the Market Rule 1 provisions governing Dispatchable Asset-Related Demand ("DARD").³

¹ Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff"), including Market Rule 1, which is Section III of the ISO Tariff. The ISO Tariff is available at www.iso-ne.com/regulatory/tariff/index.html.

² *ISO New England Inc. and New England Power Pool*, 130 FERC ¶ 61,054 (2010) ("January 21 Order").

³ Market Rule 1 is Section III of the ISO Tariff. The market rule modifications are referred to herein as the "DARD Revisions."

I. INTRODUCTION

In Order No. 719,⁴ the Commission established reforms to improve the operation of organized wholesale electric power markets and amended its regulations under the Federal Power Act (“FPA”) in the areas of: (1) demand response, including pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of RTOs and ISOs to their customers and other stakeholders. In the area of demand response, Order No. 719 required each RTO and ISO to: (1) accept bids from demand response resources in the RTO’s or ISO’s markets for certain ancillary services, on a basis comparable to other resources; (2) eliminate, during a system emergency, a charge to a buyer that takes less electric energy in the real-time market than it purchased in the day-ahead market; (3) in certain circumstances, permit an aggregator of retail customers to bid demand response on behalf of retail customers directly into the organized energy market; and (4) modify their market rules, as necessary, to allow the market-clearing price, during periods of operating reserve shortage, to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power. The Filing Parties submitted an Order No. 719 compliance filing on April 28, 2009 (the “April 28 Compliance Filing”).

Relevant to this compliance filing, the January 21 Order:

- found that “the Filing Parties have not sufficiently demonstrated compliance with this market-clearing price requirement for demand resources in the ancillary services market”⁵ – in response, the ISO provides information that demonstrates such compliance;
- required the ISO to address in the then-ongoing stakeholder process exploring the treatment of demand resources in the energy markets how the proposals under consideration would affect how demand resources are compensated in the reserves and regulation markets⁶ – in response, the ISO explains that the Commission’s issuance on March 18, 2010 of a notice of proposed rulemaking titled “Demand Response Compensation in Organized Wholesale Energy Markets” (the “Demand Response NOPR”) has redirected the focus of the New England stakeholder process away from its existing efforts and toward compliance with an eventual final rule or outcome from that proceeding, which

⁴ *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 *Fed. Reg.* 64100 (October 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (“Order No. 719”), *Order on Reh’g*, Order No. 719-A, 74 *Fed. Reg.* 37776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009) (“Order No. 719-A”), *reh’g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

⁵ January 21 Order at P 48.

⁶ *Id.* at P 49.

efforts will consider how demand resources are compensated in the reserves and regulation markets;⁷

- provided that any filing resulting from that stakeholder process (which the ISO previously stated it planned to file by June 1, 2010 to become effective June 1, 2012, consistent with the third Capacity Commitment Period) “must demonstrate how DARDs or any revised mechanism that is developed for demand response resources complies with the comparability requirements of Order No. 719 as they pertain” to these ancillary services, and the filing “must also include any of the revisions generated by our findings here”⁸ – in response, the ISO explains that New England’s filing(s) in response to an eventual final rule or outcome in the Demand Response NOPR proceeding will address comparability requirements; and
- to the extent the current DARD construct is retained, required “an examination of the current rules that require a minimum 5 MW peak load size requirement and deny DARDs the ability to aggregate”⁹ – in response, the Filing Parties submit the DARD Revisions.

II. COMPLIANCE WITH THE JANUARY 21 ORDER

A. Compliance With Market-Clearing Price Requirement for Demand Resources in the Ancillary Services Market

The January 21 Order found that the April 28 Compliance Filing did not sufficiently demonstrate compliance with the Order No. 719 requirement that all accepted bids from demand resources in the ancillary services market receive the market-clearing price in a comparable fashion to generation resources.¹⁰ The January 21 Order provided a specific scenario of concern:

For example, we can presume that a DARD with a Forward Reserve Obligation receives credit at the clearing price of the Forward Reserve Market Auction. Under such a scenario, it may be possible to find [the ISO] in compliance with the market-clearing price requirement of Order No. 719. But, Filing Parties did not provide enough information in the compliance filing to demonstrate how the tariff

⁷ *Demand Response Compensation in Organized Wholesale Electricity Markets*, Notice of Proposed Rulemaking, 75 Fed. Reg. 15362, 130 FERC ¶ 61,213 (2010) (“Demand Response NOPR”).

⁸ *Id.*

⁹ *Id.* The DARD Revisions respond to this requirement.

¹⁰ January 21 Order at P 48.

revisions with respect to DARDs without Forward Reserve Obligations (that simply have avoided costs) satisfy the requirements of Order No. 719.¹¹

The ISO provides the following additional information to demonstrate the current program's compliance with Order No. 719's comparability requirement.

A DARD without a Forward Reserve Obligation providing real-time operating reserves will receive a credit comparable to a generation resource (also without a Forward Reserve Obligation) providing real-time operating reserves. Section III.10.1.1 of Market Rule 1 defines how, for each hour, a resource's real-time reserve designation is calculated. For a DARD capable of satisfying the relevant ten minute or thirty minute contingency response, this designation is the difference between the DARD's actual consumption and its designated minimum consumption limit. A DARD's minimum consumption limit is the amount of load the DARD is prepared to consume if requested by the ISO. Section III.10.1.2 of Market Rule 1, in turn, provides that a resource's real-time reserve payment will be equal to the product of its real-time reserve designation (in MW) and the real-time reserve clearing price (\$/MWh).

For example, a DARD that is consuming 5 MW and has designated a minimum consumption limit of 1 MW that can be achieved in ten or thirty minutes will have a real-time reserve designation of 4 MW. If the real-time reserve clearing price for a particular hour is \$1.00/MWh, a DARD with a 4 MW real-time reserve designation would receive the same \$4.00 payment for that hour as a generating resource with a real-time reserve designation of 4 MW. Thus, a DARD and a generating resource (where neither of which has a Forward Reserve Obligation) receive the same credit, calculated using the same clearing price.

The ISO believes that this explanation and example provide the information required by the January 21 Order, but is prepared to provide further information if necessary.

B. Demand Resource Compensation in the Reserve and Regulation Markets

The January 21 Order required the ISO to address in the then-ongoing stakeholder process exploring the treatment of demand resources in the energy markets how the proposals under consideration would affect how demand resources are compensated in the reserves and regulation markets. The order also provided that any filing the ISO submitted as a result of that stakeholder process, which the ISO previously stated it planned to file by June 1, 2010, "must demonstrate how DARDs or any revised mechanism that is developed for demand response resources complies with the comparability requirements of Order No. 719 as they pertain" to these ancillary services.¹² The filing "must also include any of the revisions generated by [the Commission's] findings here."¹³

¹¹ *Id.*

¹² *Id.* at P 49.

¹³ *Id.*

The foregoing discussion in the January 21 Order and the New England stakeholder process referred to therein have been significantly affected by the Commission's issuance on March 18, 2010 of the Demand Response NOPR. The Demand Response NOPR proposes to revise the Commission's regulations to establish a compensation approach for demand response resources participating in organized wholesale electricity markets.

Due to these developments, the ISO has for the time being suspended efforts to make a market rule filing addressing the future treatment (and compensation) of price-responsive demand in New England. By way of background, the ISO had informed the Commission earlier this year of its plan to prepare an initial set of market rules for price-responsive demand (the "Phase 1" rules), vet them through the stakeholder process, and file them with the Commission under Section 205 of the FPA on or before April 30, 2010.¹⁴ Further, the ISO planned to file a second set of rules (the "Phase 2" rules) reflecting the Commission's rulings on the Phase 1 rules. The Phase 2 rules would have built upon the Phase 1 rules and would have completed the set of market rules needed to enable demand response resources to participate directly in supply-side of the New England energy markets.¹⁵ The Phase 1 rules would have addressed product definition, eligibility, payment rate and cost allocation. The Phase 2 rules would have addressed all relevant issues not addressed in Phase 1, including demand reduction offer parameters, real-time scheduling and dispatch of demand resources, asset enrollment requirements, measurement and verification of demand reductions, rights and obligations of demand resources, and internal market monitoring review of demand reduction offers.

The NEPOOL Markets Committee, in the lead-up to its March 23, 2010 meeting, was preparing to vote on whether to recommend that the NEPOOL Participants Committee support the ISO's proposed Phase 1 rules. Just prior to that meeting, however, the Commission issued the Demand Response NOPR, which seeks to address some of the key issues that the Phase 1 rules would have addressed, particularly the payment rate issue. Because the Commission will be addressing key issues generically in the Demand Response NOPR proceeding, the ISO withdrew its request for a NEPOOL stakeholder vote on the proposed Phase 1 market rule language.

The ISO currently contemplates that the Commission will address compensation-related issues in the Demand Response NOPR and that the ISO and NEPOOL will work to resolve remaining issues and file a comprehensive price-responsive demand proposal upon completion of the NOPR process, whether that results in a final rule or other such outcome.

Accordingly, the issues regarding the New England reserves and regulation markets referenced in Paragraph 49 of the January 21 Order and not otherwise addressed in this filing will likely not be presented to the Commission until after a final rule is issued or the Demand Response NOPR proceeding is otherwise concluded. The ISO and NEPOOL intend that these

¹⁴ See ISO filing in Docket No. ER08-830-000 (February 12, 2010), at 6.

¹⁵ *Id.*, at 6-7.

and other related issues will be discussed in the New England stakeholder process, whether conducted during the pendency of the rulemaking process, as appropriate, or in discussions designed to develop a comprehensive price-responsive demand proposal after the final disposition of the Demand Response NOPR process. Indeed, the ISO plans to continue working with the stakeholders to develop metering and other infrastructure requirements to facilitate the aggregation and dispatch of retail customers consistent with the provision of certain ancillary services in real time.

C. Removal of the 5 MW Peak Load Size Requirement and Aggregation Prohibition

The January 21 Order required, to the extent stakeholders committed to retaining the current DARD construct, “an examination of the current rules that require a minimum 5 MW peak load size requirement and deny DARDs the ability to aggregate.”¹⁶ Although the region has not yet fully addressed all the issues regarding the current DARD construct, as described herein, the Filing Parties have, however, decreased the minimum DARD size requirement and permitted aggregation in response to the January 21 Order, to the extent possible.

By way of background, the April 28 Compliance Filing contained a summary of barriers to entry – as identified by the ISO and stakeholders – relating to demand resources providing reserves.¹⁷ Two of the identified “Technical and Market Barriers” were:

The 5 MW minimum peak load requirement is a barrier for smaller demand resources to provide reserves as a Dispatchable Asset Related Demand.

The current asset registration requirements in New England specify a 5 MW minimum peak load requirement to register as a Dispatchable Asset Related Demand, which can serve as a barrier to smaller demand resources (peak load less than 5 MW) that may be able to provide reserves.

The Dispatchable Asset Related Demand infrastructure’s lack of aggregation is a barrier to demand resource providers providing reserves.

Currently, a Dispatchable Asset Related Demand must be associated with a single...customer.¹⁸

The following discussion in the April 28 Compliance Filing assessed the feasibility of addressing these two barriers:

¹⁶ January 21 Order at P 49.

¹⁷ April 28 Compliance Filing at 50.

¹⁸ *Id.* at 51.

From [the ISO's] perspective, allowing market participants with peak loads less than 5 MW to register as a Dispatchable Asset Related Demand and allowing a market participant to aggregate multiple retail customers at the same electrical location (i.e., a Node) as a Dispatchable Asset Related Demand could be accommodated within the existing Dispatchable Asset Related Demand infrastructure design. However, given that the local distribution companies are responsible for performing several of the administrative functions associated with Dispatchable Asset Related Demand registration, such as identifying the nodes from which a retail customer receives electricity service, [the ISO] cannot unilaterally remove these two barriers. To the extent that the local distribution companies can perform the additional administrative work that may result from lowering the Dispatchable Asset Related Demand's minimum peak load size and allowing retail customer aggregation, then eliminating these two barriers may be achievable.¹⁹

In light of the foregoing, the ISO initiated a stakeholder process (described further in Section III, below) to develop amendments to Market Rule 1 to reduce the DARD minimum size requirement and to allow retail customer aggregation. The DARD Revisions are the product of this stakeholder process.

Specifically, the DARD Revisions modify the definitions of "Asset Related Demand" and "Dispatchable Asset Related Demand" contained in Section I.2.2 of the ISO Tariff to read as follows:

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 electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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.

¹⁹ *Id.* at 54.

In sum, the definitional changes will reduce the Asset Related Demand and DARD minimum size threshold from 5 MW to 1 MW and allow aggregation of retail customers receiving electrical service from the same point of supply. The DARD Revisions will not require major changes in ISO systems, and thus their implementation will not interfere with or delay other efforts designed to increase demand response participation in the New England markets. Consistent with the discussion in the April 28 Compliance Filing, and as indicated in Section IV below, the effective date for the DARD Revisions will depend on the outcome of coordination activities among the ISO and the parties responsible for supporting DARD registration and metering, such as the Host Participant Meter Readers.

III. STAKEHOLDER PROCESS

The NEPOOL Markets Committee, at its March 9-10, 2010 meeting, voted to recommend that the Participants Committee support the DARD Revisions, with three abstentions. On April 9, 2010, the NEPOOL Participants Committee voted unanimously to support the DARD Revisions, with six abstentions noted, without prejudice to any future positions, inconsistent or otherwise with the positions taken at that time, as to whether Dispatchable Asset Related Demands comply with the comparability requirements of Order No. 719 as they pertain to ancillary services.

IV. REQUESTED EFFECTIVE DATE

The Filing Parties request an effective date for the DARD Revisions, with two weeks' notice from the ISO, on or after December 1, 2010. The ultimate effective date of these changes will depend on the outcome of coordination activities among the ISO and the parties responsible for supporting DARD registration and metering, such as the Host Participant Meter Readers.

V. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.²⁰ Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

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

- ◆ This transmittal letter;
- ◆ Attachment 1: Redlined tariff sheets reflecting the DARD Revisions;

²⁰ 18 C.F.R. § 35.13 (2009).

- ◆ Attachment 2: Clean tariff sheets reflecting the DARD Revisions; and
- ◆ Attachment 3: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been e-mailed.

35.13(b)(2) – The Filing Parties request that the revised tariff sheets become effective, with two weeks’ notice from the ISO, on or after December 1, 2010.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO’s website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_ptcpts_eserved.pdf. A copy of this transmittal letter and the accompanying materials have also been e-mailed to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, and to NECPUC. The names and addresses of these governors and regulatory agencies are shown in Attachment 3. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Attachment 3 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 II.C of this transmittal letter.

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

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

35.13(b)(7) – Filing Parties have no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

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

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

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

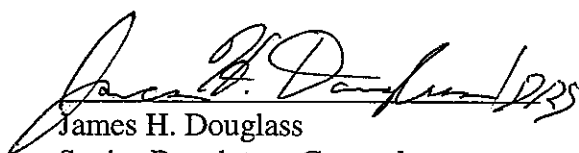
35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions contained herein.

VI. CONCLUSION

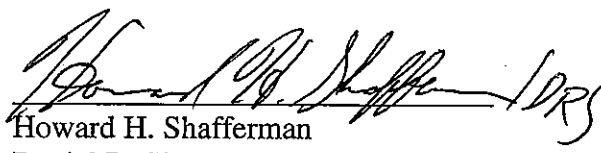
The Filing Parties request that the Commission accept the enclosed revised tariff sheets filed in response to the compliance requirements in the January 21 Order, and without modification or condition, to be effective, with two weeks' notice, on or after December 1, 2010.

Respectfully submitted,

ISO NEW ENGLAND INC.

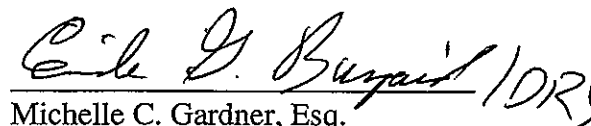


James H. Douglass
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4559
Fax: (413) 535-4379
E-mail: jdouglass@iso-ne.com



Howard H. Shafferman
Daniel R. Simon
Ballard Spahr LLP
601 13th Street, N.W.
Suite 1000 South
Washington, D.C. 20005
Tel: (202) 661-2200
Fax: (202) 661-2299
E-mail: hhs@ballardspahr.com
semranij@ballardspahr.com

NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE



Michelle C. Gardner, Esq.
Emile G. Buzaid, Esq.
Day Pitney LLP
One International Place
Boston, MA 02110
Tel: (617) 345-4697
Fax: (617) 345-4745
Email: mcgardner@daypitney.com
egbuzaid@daypitney.com

Attachments

Attachment 1

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, ~~and that~~ 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 electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

Issued by: Raymond W. Hepper, Vice President and General Counsel Effective: With notice, on or after December 1, 2010 ~~January 24, 2010~~

Issued on: April 21, 2010 ~~October 26, 2009~~

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having~~meets the requirements of the ISO New England Manuals to~~ have its energy consumption modified in Real-Time in response to Dispatch Instructions~~because of its ability to respond to remote dispatch instructions from the ISO.~~ has A Dispatchable Asset Related Demand ~~must have~~ 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 ~~ISO Dispatch I~~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.

Attachment 2

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 electrical supply, with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration.

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.

Attachment 3

The Honorable John E. Baldacci
One State House Station
Rm. 236
Augusta, ME 04333-0001
Karin.tilberg@maine.gov
Kelly.arata@maine.gov

John Shea
Power Planning Committee
New England Governors' Conference
Inc.
76 Summer Street, 2nd floor
Boston, MA 02110-1226
Charon2@msn.com

Heather Hunt
Executive Director
NESCOE
242 Whippoorwill Lane
Stratford, CT 06614
HeatherHunt@nescoe.com
HReiter@stinson.com

Rhode Island Public Utilities
Commission
89 Jefferson Blvd.
Warwick, RI 02888
Sscialabba@ripuc.state.ri.us
nucci@puc.state.ri.us
Proberti@puc.state.ri.us

The Honorable M. Jodi Rell
State Capitol
210 Capitol Ave.
Hartford, CT 06106
Governor.Rell@ct.gov

New Hampshire Public Utilities
Commission
21 South Fruit Street
Ste. 10
Concord, NH 03301-2429
RegionalEnergy@puc.nh.gov

Massachusetts Dept. of Public Utilities
One South Station
Boston, MA 02110
John.j.keene@state.ma.us

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701
HReiter@stinson.com
Hans.mertens@state.vt.us

Harvey L. Reiter, Esq.
Counsel for New England Conference
Of Public Utilities Commissioners,
Inc.
c/o Stinson Morrison Hecker LLP
1150 18th Street, N.W., Ste. 800
Washington, DC 20036-3816
HReiter@stinson.com

William M. Nugent, Executive
Director
New England Conference of Public
Utilities Commissioners
50 Forest Falls Drive, Suite 6
Yarmouth, ME 04096-6937
director@necpuc.org

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018
Maine.puc@maine.gov

Connecticut Dept. of Public Utilities
10 Franklin Square
New Britain, CT 060512605
brenda.henderson@po.state.ct.us
and robert.luysterborghs@po.state.ct.us

The Honorable John H. Lynch
Office of the Governor
26 Capital Street
Concord NH 03301
governorlynch@nh.gov