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January 21, 2003

VIA HAND DELIVERY

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street
Washington, D.C. 20426

Re: New England Power Pool and ISO New England Inc. Docket No. ER02-2330-___
Report of Compliance

Dear Secretary Salas:

Pursuant to Rule 1907 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.1907 (2002), the New England Power Pool ("NEPOOL") Participants Committee[1] and ISO New England Inc., ("ISO-NE") hereby file an original and five (5) copies of this transmittal letter and proposed changes to NEPOOL Market Rule 1 ("Market Rule 1") to comply with the Commission's December 20, 2002 "Order On Rehearing and Accepting Compliance Filings" in the above-captioned docket. New England Power Pool, 101 FERC ¶ 61,344 (2002) (the "December 20 Order"). The Market Rule 1 changes are included in Attachment 1 of this Report. In addition to changing Market Rule 1, this Report of Compliance responds to the directives of the

[1] Capitalized terms used but not defined in this filing are intended to have the same meaning given to such terms in Section 1 of the Restated New England Power Pool Agreement, Section 1 of the Restated NEPOOL Open Access Transmission Tariff and Section 1.3 of Market Rule 1.

December 20 Order by providing further information on billing determinants proposed for the allocation of Operating Reserve Charges and by confirming the Commission's understanding regarding the allocation of Auction Revenue Rights ("ARRs") and the meaning of "Congestion Paying LSE."

As the Commission is aware, ISO-NE is currently planning to implement its Standard Market Design on March 1, 2003, with bids for the initial auction of one month of Financial Transmission Rights ("FTRs") to be submitted beginning on February 10, 2003. The ISO-NE Board intends to make a final decision on the implementation date at a February 6 meeting, following consideration of: (1) any additional guidance the Commission may provide prior to that time; (2) the results of a third market trial that was recently completed, and; (3) input received from the Participants Committee and state regulators. Once the SMD Effective Date occurs, it may be impossible to adjust settlements retroactively to effect any additional SMD compliance changes the Commission might conclude are necessary. Further, it is highly desirable for the details of the New England Load Response Program (the "Load Response Program") to be defined soon so that marketing of that Program can begin. A final Commission order on this compliance filing will provide market certainty that will enhance the success of these important market changes. Accordingly, NEPOOL and ISO-NE urge the Commission to expedite its review of this compliance filing.

I. BACKGROUND

On July 15, 2002, the NEPOOL Participants Committee and ISO-NE jointly tendered for filing Market Rule 1 and its related appendices pursuant to Section 205 of the Federal Power Act. Market Rule 1 is intended to embody a revised wholesale market design, commonly referred to in New England as the Standard Market Design ("SMD"), for the implementation of Locational Marginal Pricing ("LMP") and a multi-settlement system.

On September 20, 2002, the Commission issued its "Order Accepting In Part And Modifying In Part Standard Market Design Filing And Dismissing Compliance Filing" (the "SMD Order") in this proceeding.[2] In response to the SMD Order, NEPOOL and ISO-NE, as well as other parties, submitted rehearing requests and NEPOOL and ISO-NE submitted compliance filings. On December 20, 2002, the Commission issued its "Order on Rehearing and Accepting Compliance Filings."[3] The December 20 Order required the NEPOOL Participants Committee and ISO-NE to make a number of modifications to Market Rule 1.[4] The required changes and NEPOOL's and ISO-NE's compliance are described in Section II of this letter below, and address changes that both NEPOOL and ISO-NE believe are in full compliance with the December 20 Order. Section III of this transmittal letter provides the further information and explanations required by the

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[2] New England Power Pool et al., 100 FERC ¶ 61,287 (2002).

[3] New England Power Pool et al., 101 FERC ¶ 61,344 (2002)

[4] See Id. at P 28, 45, 47, 48, 54, and 75.

December 20 Order regarding the distinctions between different methods of allocating Operating Reserve Charges, as well as a confirmation of the Commission's understandings of the ARR allocation process and the meaning of the term Congestion Paying LSEs.

At its January 10, 2003 meeting, the NEPOOL Participants Committee approved the Market Rule 1 changes reflected herein.

II. CHANGES TO MARKET RULE 1 EFFECTING COMPLIANCE

1. Level 1 Mitigation

In the December 20 Order, the Commission "reject[ed] [the] proposal for Level 1 Mitigation without prejudice to a filing that evaluates any remaining structural problems and a proposal that targets only those suppliers that obtain market power as a result of these structural problems."[5] In compliance with the Commission's directive, Section 5.3.1 of Appendix A to Market Rule 1 has been eliminated.[6] Conforming changes have also been made to Sections 3.1.1, 5.3.2, 5.3.3, 5.4, 5.5.2, 5.5.3, 5.7.4 and Exhibit 1 of Appendix A.

During the review of the compliance-related changes to Appendix A at the Participants Committee meeting, concerns were expressed with the proposal to eliminate

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[5] December 20 Order at P 28.

[6] See Attachment 1. Consistent with the December 20 Order, ISO-NE is currently considering various options regarding potential replacements for the "level 1 mitigation" that would target only those suppliers with market power as a result of structural problems.

Section 3.1.1 of that Appendix. That Section provides that ISO-NE will consult with Participants regarding conduct identified by ISO-NE as potentially inappropriate prior to imposing general mitigation. ISO-NE recommended that Section 3.1.1 be completely removed since it related only to the general mitigation thresholds directed to be eliminated by the December 20 Order. ISO-NE clarified and confirmed that that the removal of this Section was not intended to preclude or reduce the consultative process related to mitigation where appropriate. A motion to amend the proposed compliance changes was made to retain the language within Section 3.1.1, but modifying that Section by deleting the reference to the now inapplicable "general markets threshold" for mitigation language contained within the introductory sentence of that provision. Some objected to that proposed change as unnecessary and beyond compliance, and a change that would alter the original intent of that Section. The motion to retain a modified Section 3.1.1 failed to achieve the required support for its adoption with a 44.57% vote in favor (Attachment 4, Vote 3, tabulates this Participants Committee vote.). The original resolution to approve the compliance-related changes passed by a show of hands with no opposition and 15 abstentions.

2. Demand Response

A. Compliance Changes Unrelated to the New England Demand Response Initiative

In Paragraph 48 of the December 20 Order, in response to the Request for Clarification and/or Rehearing of the Connecticut Department of Public Utility Control, the Commission stated that "[a]s to allocating the costs associated with the Real-Time Demand Response Program system-wide, we will allow such allocation as an initial matter, in order to encourage the development of demand response programs." As originally filed, Appendix E specified that these costs were to be allocated on a zonal basis pursuant to the applicable Load Obligation (Day-Ahead Load Obligation for the Day-Ahead Program and Real-Time Load Obligation for the Real-Time Programs).

Prior to the issuance of the December 20 Order, NEPOOL had approved different (but not un-reconcilable) changes regarding the allocation of Load Response Program costs. Those previously approved changes have been filed with the Commission pursuant to Section 205 of the Federal Power Act on December 27, 2002, in Docket No. ER03-345-000 (the "December LRP Filing"). In the December LRP Filing, NEPOOL proposed revisions to Appendix E to change the basis for allocating to Participants the costs of the Load Response Programs from Load Obligation to Network Load. The December LRP Filing is currently pending before the Commission, and NEPOOL would note that the cost allocation proposal contained in that filing is supported by the NEDRI participants.[7]

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[7] On January 15, 2003, the NEDRI participants endorsed NEPOOL's proposal to allocate demand response program costs to Network Load. The text of NEDRI's recommendation concerning cost allocation follows: "*Allocate 2003 ISO RDR program costs to network load*. Given the limited scale and objectives of the proposed 2003 price responsive load programs, NEDRI supports NEPOOL's proposal to allocate program costs to network load. NEDRI further supports recovery of these costs from ratepayers." The NEDRI participants approved this recommendation unanimously (PJM and the public utility commissions from New Hampshire, Massachusetts and Maine abstained).

The cost allocation pronouncements contained within paragraph 48 of the December 20 Order do not reflect the proposal contained within the December LRP Filing. Whether the Load Response Program costs are allocated locally or system-wide is a separate issue from the use of Network Load or Real-Time Load Obligation as the billing determinant. Load Response Program costs can be allocated in accordance with a Participant's share of Network Load within a particular Zone, or in accordance with a Participant's share of the entire Network Load within NEPOOL (i.e., system-wide).

The December LRP Filing explained that, due to the significant software development issues resulting from the proposed changes, ISO-NE would be unable to implement the cost allocation change to Network Load by the March 1, 2003 date currently contemplated as the SMD Effective Date. Accordingly, the December LRP Filing explained that this allocation-related change is proposed to become effective for both the Day-Ahead and Real-Time programs when the Day-Ahead Demand Response Program is implemented, as set forth in Sections 1.4 and 2.1 of Appendix E. Until that time, the costs of the Real-Time program will be allocated on the basis of Real-Time Load Obligations, as defined and quantified in Market Rule 1.

When the NEPOOL Participants Committee considered the Load Response Program cost allocation changes directed by the December 20 Order, at least one Participant sought changes that would mandate an allocation to Network Load as of the SMD Effective Date (i.e., without the delay contemplated by the December LRP Filing).

ISO-NE explained in response that that the software development issues would not allow for the change requested in the near-term, and that it would be highly impractical for ISO-NE to resettle the markets after the software changes were made. In addition, some Participants viewed the "we will allow" language in Paragraph 48 as permissive rather than mandatory, [8] but the more widely accepted view was that the December 20 Order directed a system-wide allocation of Load Response Program costs.

[8] In addition, during the NEPOOL discussion of the proposed compliance changes, some Participants questioned the appropriateness of allocating the costs of all of the Load Response Programs system-wide when the Commission referenced only the Real-Time Demand Response Program. When presenting these draft compliance changes to the Participants, ISO-NE explained that the logic of the Commission in revising the cost allocation for this one program should apply to the other programs as well, since they are similar in purpose and effect. For example, the Real-Time Profiled Response Program is similar to the 30-minute Real-Time Demand Response Program, but for the fact that interval meters are not required for participants in the Real-Time Profiled Response Program. Similarly, the Day-Ahead Demand Response Program is a reliability-focused program as is the Real-Time Demand Response Program. Moreover, ISO-NE expressed concern that different cost allocation methodologies for different Load Response Programs would be exceedingly burdensome on its operations. This last point is particularly noteworthy given that, consistent with the December 20 Order, ISO-NE intends to develop program revisions to allow participants in the Day-Ahead Demand Response Program whose bids are not accepted in the Day-Ahead Market to participate in the Real-Time Price Response Program. Accordingly, ISO-NE proposed that NEPOOL comply with the Commission's order by allocating all Load Response Program costs system-wide. If ISO-NE's interpretation that the Commission-directed cost allocation methodology was intended to apply to both the Real-Time and Day-Ahead components of the Load Response Program and not just the Real-Time components is incorrect, that issue can be rectified before the Day-Ahead Demand Response Program is implemented later in the year.

Following that explanation and discussion, the Participants Committee approved by a show of hands vote, with four opposing and seven Participants abstaining[9], the changes revising Sections 1.4 and 2.3 of Appendix E.[10]

In addition to cost allocation issues, in Paragraph 45 of the December 20 Order, the Commission directed that the bid ceiling for the Day-Ahead Demand Response Program be raised from $500/MWh to $1,000/MWh. This change is included in Section 2.2 of Appendix E consistent with the December 20 Order.

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[9] The four entities in opposition are: Northeast Utilities System Companies, Central Maine Power Company, TransCanada Power Marketing Ltd., and Bangor Hydro-Electric Company. The seven entities abstaining are: LIPA, PSEG Energy Resources & Trade LLC, PG&E Energy Trading, Entergy Nuclear Generation Company, Exelon Generation Company, LLC, Virginia Electric and Power Company, and State of Maine.

[10] The changes revising Sections 1.4 and 2.3 are contained on Sheet Nos. 602 and 603, which are currently pending Commission action in the December LRP Filing Docket. The compliance changes approved by NEPOOL consolidate the changes required by the December 20 Order with the changes to those sheets pending in the December LRP Filing Docket. Accordingly, Sheets 602 and 603 submitted herewith have been designated as Substitute First Revised Sheet Nos. 602 and 603, and are requested to be effective on February 23, 2003 for transactions on and after the applicable effective dates set forth in Market Rule 1 and Appendix E. Should the Commission require changes to Sheet Nos. 602 and 603 in the December LRP Filing Docket, NEPOOL will file appropriate substitute sheets to reflect the outcome of those proceedings.

B. NEDRI-related Compliance Changes[11]

In Paragraph 47 of the December 20 Order, the Commission directed NEPOOL "to make a filing revising its demand response programs to reflect the results of the NEDRI process." The NEDRI process has, among other things, discussed and debated changes to the Load Response Programs previously filed with Commission by NEPOOL and ISO-NE as part of New England's SMD arrangements. NEPOOL understands that the process considers a broad range of proposals to enhance load response within New England, including some recommendations that are environmentally-related, retail jurisdictional or related to future considerations. ISO-NE and NEPOOL have focused on those preliminary recommendations of NEDRI contained in early draft reports as of the

[11] The website of the New England Demand Response Initiative ("NEDRI") indicates that its function is as follows: "aimed at developing a comprehensive, coordinated set of demand response programs for the New England regional power markets. NEDRI's goal is to outline workable market rules, reliability standards, and regulatory criteria to incorporate a demand response capability into the electricity wholesale and retail markets. The Initiative will promote best practices and coordinate policy initiatives, not replace the functions that the ISO and other organizations must perform to design and implement demand-side programs."

ISO-NE believes that the NEDRI process has been useful in assembling the New England electric industry stakeholders to focus on demand response issues. ISO-NE supports *as a whole* the recommendations summarized in its Regional Demand Response chapter, which were unanimously approved by NEDRI participants attending the NEDRI plenary session on January 15, 2003 (this conflicted with a regularly scheduled NEPOOL Markets Committee meeting also held on this date). We note that some of the votes on specific issues in that chapter were dependent on adoption of the recommendations as whole. A copy the NEDRI Regional Demand Response chapter can be found at the following World Wide Web link:
http://nedri.raabassociates.org/Articles/Regional_DRChapter.1.21.doc

date of the December 20th Order that were directed at the Load Response Programs that had been accepted by the Commission for the NEPOOL Control Area.

During the review of the preliminary NEDRI recommendations following the issuance of the December 20 Order, many Participants expressed concern and/or objection to a requirement that NEPOOL be forced to accept and implement recommendations proposed by another organization that was not party to the voluntary NEPOOL arrangements or subject to a Commission-approved decision-making process. At the same time, Participants were dedicated to complying with the Commission's directives and desired to satisfy the Commission's intentions in this regard. Accordingly, the Markets Committee reconsidered the substance of the preliminary NEDRI recommendations and again was unable to garner sufficient support for these recommendations principally because of concerns by many that the recommendations would not send the proper market signals.[12] Nonetheless, the Participants Committee voted on January 10 with 90.56% in support (Attachment 4, Vote 2, tabulates this Participants Committee vote) to approve the changes to Appendix E that would

[12] At a high level, many Participants at the Markets Committee opposed the NEDRI recommendations out of a belief that they simply sought to increase the payments (through increases to the floor prices) made to load reductions requested pursuant to a non-market, reliability-based program otherwise inconsistent with the competitive markets designed for SMD. Concerns were also expressed that extending such a program, as recommended by NEDRI, may preclude the implementation of necessary improvements or modifications to the program. Finally, the Markets Committee did not consider NEDRI's recommended change to reduce the annual fee for non-Participants at its November 25 meeting because ISO-NE did not recommend this change as appropriate for a program being implemented at the wholesale market level.

implement the NEDRI preliminary recommendations that had been made at that time.[13] The approval was with the express understanding that the changes were solely to comply with the December 20 Order and without prejudice to Participants challenging the substance of those changes. Further, it was with the direction that NEPOOL also file a request for rehearing to the extent the Commission intended to require any changes beyond those approved.[14]

The specific changes now before the Commission are contained in Sections 1.1, 1.3, 3.3 and 3.5 of Appendix E to Market Rule 1.[15] In Section 1.1 of Appendix E, the annual fee assessed on non-Participants who take part in the Load Response Program has been reduced from $5,000 per year to $500 per year. The duration of the program has

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[13] At the Participants Committee, the debate over the appropriateness of the NEDRI-related compliance obligations culminated in a motion to amend the resolution approving such changes that would have included the NEDRI recommendations as an attachment to NEPOOL's compliance filing but not as actual changes to the Program's provisions unless and until such provisions were found to be unjust and unreasonable by the Commission. That motion to amend failed with approximately 40% of Participants voting in favor of the amendment. (Attachment 4, Vote 1, tabulates this Participants Committee vote.)

[14] Subsequent to the December 20 Order, ISO-NE's development of changes to Appendix E and the Participants Committee meeting on January 10th, NEDRI did in fact include one additional recommendation concerning the Load Response Program. That recommendation concerned allowing participants in the Day-Ahead Demand Response Program to be able to also participate in the Real-time Demand Response Program (in addition to the Real-Time Price Response Program) if they qualify. This recommendation will be considered by NEPOOL and any additional changes approved as a result of that consideration will be filed with the Commission pursuant to Section 205 of the Federal Power Act.

[15] <u>See</u> Attachment 1, Sheet Nos. 601, 602 and 604.

been increased to three years through revisions contained within Section 1.3.[16] In Section 3.3, the minimum guaranteed payment to participants in the 30-minute Real-Time Demand Response Program has been changed from $150/MWh to $500/MWh. Similarly, the minimum guaranteed payment to participants in the 2 hour Real-Time Demand Response Program has been changed from $100/MWh to $350/MWh.

NEPOOL and ISO-NE request prompt Commission action on the resolution of these Load Response Program issues and would note that resolution of the current uncertainty surrounding these programs will enable program providers to fully understand and market these programs in advance of the summer peak-demand season.

3. Proxy CT Safe Harbor Bid Cap

In the December 20 Order, the Commission granted ISO-NE's request for rehearing concerning limitations on the use of the proxy CT safe harbor bid cap designed for Designated Congestion Areas ("DCAs").[17] These limitations on the implementation of the DCA-related Appendix A provisions were originally imposed by the Commission following its original review and acceptance of Market Rule 1. In light of the Commission's reversal on this issue, Sections 5.3.2 and 5.3.3 of Appendix A to Market

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[16] As noted in NEPOOL's Motion for Clarification or, in the Alternative, Rehearing, expanding the duration of the Program should not be considered a prohibition against NEPOOL and ISO-NE refining that Program based upon lessons learned.

[17] See December 20th Order P 21.

Rule 1, and Section 1.2 of Exhibit 2 to that same Appendix, are being revised to reinstate the DCA provisions as originally proposed.[18]

4. Excepted Transactions

In Paragraph 75 of the December 20 Order, the Commission directed the deletion of new language in Section 2.1 of Appendix C that was submitted in the October 21, 2002 compliance filing. The Commission found that this language, which specified the scheduling and ARR treatment of Excepted Transactions that are also External Transactions, was an inappropriate submission in a compliance filing. In compliance with the Commission's directive, Section 2.1 of Appendix C has been revised to delete this language.[19]

5. Qualified Upgrade Awards

In Paragraph 54 of the December 20 Order, the Commission granted the request for clarification submitted by Duke Energy North America, LLC ("DENA") and directed ISO-NE to calculate the MW value of the increase in transfer capability created by a transmission upgrade. In addition the Commission specified that the amount of ARRs awarded should be based on this calculation. On January 14, 2003, the Markets Committee recommended that the Participants Committee approve changes to NEPOOL Manual No. 6 (Financial Transmission Rights Manual) that specifically recognize that the

[18] See Attachment 1.

[19] See Attachment 1, Sheet No. 603.

Qualified Upgrade Award calculation is in accordance with the Commission's rulings. These changes are found in Section 8.2 of Manual 6 and can be found on ISO-NE's website.[20] They have not yet been considered by the NEPOOL Participants Committee but are expected to be voted on at the Participants Committee February 5, 2003, meeting.

III. FURTHER INFORMATION REQUESTED BY THE COMMISSION

As noted in the introduction to the Report of Compliance, the Commission seeks further information on two issues addressed within the December 20 Order so as to confirm its understanding on ARR-related issues as well to allow it to render a decision on the proposal concerning the allocation of Operating Reserve Charges contained within Market Rule 1. Through the information and discussion contained below, NEPOOL and ISO-NE hereby respond to the Commission's directives on these issues.

1. Congestion Paying LSEs

In Paragraphs 60 and 61 of the December 20 Order the Commission states its understanding of the definition of Congestion Paying LSE and asks ISO-NE to file a statement explaining whether the Commission's understanding is correct, and if incorrect, to explain how it is incorrect.

ISO-NE states that the Commission's understanding of the term "Congestion Paying LSE" as set forth in paragraphs 60 and 61 of the December 20 Order appears to

[20] See http://www.iso-ne.com/committees/markets/2003_01_1415/A5_M-06_Financial%20Transmission%20Rights_Revison%201.doc

be correct with the following clarification. In paragraph 60, the Commission states: "... it is our understanding that each entity serving energy to load would pay congestion costs, either by virtue of purchasing energy in ISO-NE's spot market or by paying transmission congestion charges for transmission service to move bilaterally-contracted energy to the load." Internal bilateral contracts in NEPOOL are financial in nature and do not impact the physical operation of the system. Therefore, there is no transmission service associated specifically with such transactions. An internal bilateral contract for load simply transfers the obligation to serve a load as reflected in ISO-NE's settlement system by increasing the seller's Real-Time Load Obligation and reducing the buyer's Real-Time Load Obligation at the locations specified in the internal bilateral contract submittal. As a result, the seller will be recognized in the settlement system as the entity responsible for Congestion Costs based on the Congestion Component of the locational marginal prices at the locations specified in the contract submittal to the market system.

The Congestion Paying LSE definition contains the entire set of Transmission Customers that are eligible to receive ARRs: i.e., Transmission Customers who pay for Regional Network Service or Long-Term Firm Point-to-Point Transmission Service under the NEPOOL Tariff *and* who pay Congestion Costs.[21] In addition, the definition

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[21] In the course of preparing this Compliance Filing, NEPOOL and ISO-NE have discovered that the term "Transmission Customer" has not been deleted from some places in Market Rule 1 (definition of NEMA LSE and Appendix C, Sections 1 and Section 2.2) where it should have been deleted after the change in the definition from "Congestion Paying Entity" to "Congestion Paying LSE". Only that set of Transmission Customers specified in the definition of Congestion Paying LSE is intended to receive ARRs.

includes the entities to whom those Transmission Customers transfer their obligation to supply load (in accordance with NEPOOL System Rules).

2. Real Time Load Obligation Deviation

In paragraph 92 of the December 20 Order, the Commission further directs ISO-NE and NEPOOL to file additional rationale for their decision to use Real-Time Load Obligation Deviation ("RTLOD") instead of Real Time Adjusted Load Obligation Deviation ("RTALOD") when allocating Operating Reserve charges. The Commission required ISO-NE and NEPOOL to answer three distinct questions: (1) clarify the difference between RTLOD and RTALOD; (2) distinguish between internal bilateral transactions for load and internal bilateral for energy; and (3) elaborate on the flexibility RTLOD affords generators selling to marketers.

As the Commission is aware, NEPOOL and ISO-NE have concluded that it is better to use RTLOD instead of RTALOD as part of the allocation processes of both the non-synchronized condensing Operating Reserve Charges for the Real-Time Energy Market and the Real-Time Operating Reserve Charges for Daily RMR Resources. Section 3.2.1, as acknowledged by the Commission, defines the difference between these two billing determinants. Included as Attachment 3 to this Compliance Report is information provided by ISO-NE that responds to items 1 and 2 above. This attachment further clarifies for the Commission the difference between RTLOD and RTALOD and

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NEPOOL and ISO-NE expect to make an errata filing to correct any errors found in Market Rule 1, including the correction that will remove the term "Transmission Customer(s)" from the sections specified in this footnote.

explains the distinction between internal bilateral transactions for load and internal bilateral transactions for energy.

In response to the Commission's request that NEPOOL and ISO-NE elaborate on the flexibility that RTLOD affords generators and marketers, an explanation of the source of Operating Reserve Charges is necessary to better explain why ISO-NE and NEPOOL propose to allocate the charges to RTLOD. The Operating Reserve Charges in question are uplift costs driven by the commitment of generators in the Day-Ahead Market clearing process and those committed to assure reliability pursuant to the subsequent Reserve Adequacy Analysis ("RAA") or any other subsequent unit commitment. The commitment of Resources pursuant to the RAAis typically driven by underbidding of demand (load) in the Day-Ahead Market or due to unforeseen changes in system or regional conditions. Bilateral transactions for the sale and purchase of energy in the Real-Time Energy Market (internal bilateral transactions for energy), however, are financial only and simply reflect hedges against the Real-Time Energy Market price (the Real-Time LMP, Real-Time Zonal price or Real-Time Hub price depending on the nature of Real-Time imbalance hedge sought). These financial transactions serve an important purpose in hedging supplier and load exposures to spot market prices. Accordingly, it would be both inefficient and inappropriate to allocate reliability commitment costs to these transactions. Doing so would transform the existing bilateral transactions for energy settled in the Real-Time Energy Market from an imbalance hedge to a load obligation hedge (where the buyer would be forced to buy energy imbalance plus responsibility for synchronized reserve costs). As noted in the prior NEPOOL and ISO-NE response on this issue, internal bilateral transactions to transfer load obligations do exist. The Commission should not, however, eliminate the existing ability to enter into transactions to hedge against exposure to the Real-Time Energy Market by adopting a proposed change to the Operating Reserve Charge allocator.

Such an outcome would be inefficient for several reasons. First, it would reduce trading liquidity at a time when it is already experiencing lower activity from the current credit challenges in the industry. This additional reduction in hedging activity in the Real-Time Energy Market would occur because the scope of counterparties or their risk exposure would change. Today, generators or their long term bilateral buyers that have not sold their generation in the Day-Ahead Energy Market are able to lock in their compensation for energy imbalance in advance of Real-Time in order to reduce revenue uncertainty inherent in the Real-Time LMP price. While some of this hedging may occur in the Day Ahead Energy Market, it is quite likely that some generating capability will still face higher Real-Time dispatch levels than Resources cleared Day-Ahead. Under the Real-Time energy imbalance form of trading using the RTLOD, generators may face some risk in conducting such a sale to the extent they experience a forced outage between execution of sale and Real-Time, but they can physically hedge most other risks associated with their sale. Further, since SMD will allow such self-scheduled increases at other sites on one hour notice, even a forced outage risk can often be covered through increased generation at the Participant's other facilities. Eliminating this type of energy imbalance transaction through the conversion to a Real-Time Adjusted Load Obligation Deviation allocator, however, would introduce greater risk and more importantly, risk that generator sellers could not physically hedge. If the RTALOD proposal were to be directed by the Commission, there would be no practical way for a supplier to avoid these charges if forced to assume them under a Real-Time energy trade. Such an outcome would require those suppliers that continued to trade energy (now energy imbalance plus Operating Reserve Charges) through a broader transaction type to reflect a premium to cover the Operating Reserve Charges and their inherent unpredictability. Today, marketers often serve as an intermediary between generator suppliers and load serving entities. This increased liquidity improves price discovery and enhances competition. NEPOOL's stakeholders fear that the allocating Operating Reserve Charges via RTALOD would both decrease supplier participation and liquidity in the Real-Time Energy Market and increase the costs to serve load through higher risk premiums required of the remaining sellers of the composite product (spot market energy plus Operating Reserve Charges). The latter problem may manifest itself through numerous layers of premiums where several marketers' trades occur between the initial purchase from a generator and ultimate sale to a load-serving entity.

Finally, as NEPOOL and ISO-NE have repeatedly stated, other transactions do exist for load serving entities who wish to hedge against the reliability-based Operating Reserve Charges. They are called internal bilateral transactions for load. There is simply no reason to require that internal bilateral transactions for energy also transfer Operating

Reserve Charge responsibility and the use of RTALOD would cause such a transfer and eliminate the primary and most important distinctions between these two types of transactions provided for under the SMD.

III. ADDITIONAL SUPPORTING INFORMATION

This filing submits those changes to NEPOOL Market Rule 1 that are required to comply with the December 20 Order. Included herewith are the following documents:

- This filing letter;
- Revised sheets of Market Rule 1 and its related Appendices (Attachment 1);
- Relevant portions of Market Rule 1 and its related Appendices marked to show the changes made since last submitted to the Commission (Attachment 2);
- Additional information provided by ISO-NE on Real Time Load Obligation Deviation and Congestion Paying LSEs (Attachment 3);
- The voting results of the Participants Committee on the changes to Market Rule 1 and its related Appendices as required by the Commission's December 20 Order (Attachment 4);
- List of NEPOOL Participants Committee members and alternates (Attachment 5);
- List of governors and utility regulatory agencies in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut to which a copy of this filing has been sent (Attachment 6);
- A draft form of notice, suitable for publication in the Federal Register, and a diskette containing this form of notice, in accordance with Section 35.8 of the Commission's Regulations (Attachment 7).

Copies of this Report of Compliance and the accompanying materials are being served on all persons on the Commission's official service lists in the captioned proceedings. Attachment 5 to this filing lists the names and addresses of each of the Participants Committee members and alternates who represent all Participants in NEPOOL. All Participants Committee members have been furnished with an electronic copy of this filing.[22] A copy of this Report of Compliance has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the NEPOOL Control Area. The names and addresses of these governors and regulatory agencies appear in Attachment 6. In accordance with the Commission's rules and practice, there is no need for the entities identified in Attachments 5 and 6 to be included on the Commission's official service lists in the captioned proceeding unless such entities already are or become intervenors in this proceeding.

Correspondence and communications regarding this filing should be addressed to the Chair of the NEPOOL Participants Committee and the undersigned as follows:

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And to the ISO as follows:

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[22] Pursuant to changes to Section 21.13 (e) of the Restated NEPOOL Agreement, which was accepted by the Commission in New England Power Pool, 90 FERC ¶ 61,019 (2000), NEPOOL Participants can be served electronically rather than by hard copy.

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Please acknowledge receipt of the foregoing by date-stamping and returning to the hand delivery messenger the extra copy of this filing.

Respectfully submitted,
New England Power Pool Participants Committee

By: David T. Doot
Its Counsel

ISO New England Inc.

By: Kathleen A. Carrigan
Its General Counsel

SKS/DTD
Attachments

cc : Persons designated on the Official Service List in Docket No. ER02-2330-000
Entities listed in Attachments 5 and 6

ATTACHMENT 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

Table of Contents — Page

1. PURPOSE AND OBJECTIVES 204
   1.1 Thresholds. 204
   1.2 Other Conduct. 204
2. MITIGATION PRINCIPLES 205
   2.1 Conduct Subject to Mitigation. 205
   2.2 Conditions for the Imposition of Mitigation Measures. 205
      2.2.1 Market Impact. 205
      2.2.2 Conduct Inconsistent with a Competitive Market. 205
   2.3 Categories of Conduct that May Warrant Mitigation. 205
      2.3.1 In General. 205
      2.3.2 Conduct Not Deemed Anti-Competitive. 206
      2.3.3 Physical Withholding by a Participant. 206
      2.3.4 Other Withholding of Supply Offers. 206
      2.3.5 Anti-Competitive Increment Offers and Decrement Bids. 206
      2.3.6 Other Conduct. 207
   2.4 Other Monitoring Objectives. 207
      2.4.1 Monitoring Targets. 207
      2.4.2 Reports. 208
   2.5 Further Changes. 208
   2.6 Duration of Mitigation Measures. 208
3. CONSULTATION REQUIREMENTS 209
   3.1 In General. 209
      3.1.1 Reserved. 209
      3.1.2 Consideration of Information in All Cases. 209
      3.1.3 Advance Consultation by Participant. 210
      3.1.4 Participant Access to Its Reference Levels. 210

Table of Contents **Page**

4. PHYSICAL WITHHOLDING....211
- 4.1 Identification of Conduct Inconsistent with Competition. 211
- 4.2 Thresholds for Identifying Physical Withholding. 211
  - 4.2.1 Initial Thresholds. 211
  - 4.2.2 Adjustment to Generating Capacity. 211
  - 4.2.3 Withholding of Transmission. 212
  - 4.2.4 Resources in Congestion Areas. 212
- 4.3 Hourly Market Impact and Operating Reserve Thresholds. 212
- 4.4 Imposition of Mitigation Measures. 212

5. ECONOMIC WITHHOLDING AND UNECONOMIC PRODUCTION 213
- 5.1 Purpose. 213
- 5.2 Applicability. 213
- 5.3 Thresholds for Identifying Economic Withholding. 213
  - 5.3.1 General Thresholds. 213
  - 5.3.2 Thresholds Applicable in Designated Congestion Areas. 214
  - 5.3.3 Thresholds Applicable in Other Congestion Areas. 214
- 5.4 Threshold for Identifying Uneconomic Production. 215
- 5.5 Hourly Market Impact and Operating Reserve Thresholds. 215
  - 5.5.1 Initial Investigation. 215
  - 5.5.2 Reserved. 215
  - 5.5.3 Calculation of Price Impact. 216
- 5.6 Calculation of Resource Reference Levels. 217
  - 5.6.1 Methods for Determining Reference Levels. 217
  - 5.6.2 Insufficient Data. 218
- 5.7 Mitigation Measures 218
  - 5.7.1 Manual Review Prior to Mitigation. 218
  - 5.7.2 Conditions for Imposition of Mitigation Measures. 218
  - 5.7.3 Level of Default Offers. 219
  - 5.7.4 Implementation. 219

6. RELIABILITY MUST-RUN AGREEMENTS 220
- 6.1 Mitigation Agreements. 220
- 6.2 Cost-of-Service Agreements. 220
- 6.3 Filing with the Commission. 220

7. MITIGATION OF DEMAND BIDS. 220

3. CONSULTATION REQUIREMENTS

3.1 In General. If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified below, on one or more prices or Operating Reserve payments in the NEPOOL Market administered by the ISO, the ISO will take the steps set forth in this Section 3:

3.1.1 Reserved.

3.1.2 Consideration of Information in All Cases. In every case, the ISO will consider all available explanations of behavior that are based on a Participant's cost of providing any market product, including

(a) Any relevant opportunity costs,

(b) The need to shape bids and offers for a Limited Energy Resource to maximize the economic value from that Resource over time given the unique characteristics of the Resource, and

(c) any special price limitations applicable to dual-fuel resources.

5. ECONOMIC WITHHOLDING AND UNECONOMIC PRODUCTION

5.1 Purpose. This Section defines thresholds of economic withholding in constrained areas. If conduct is detected that exceeds the thresholds specified in Sections 5.3 or 5.4 and the ISO determines that there is a market impact, as provided in Section 5.5, the conduct shall be remedied by the prospective application of a Default Offer as described in Section 5.7.

5.2 Applicability. Only Resources required to offer in the Day-Ahead market will be evaluated for economic withholding in the Day-Ahead market. All Supply Offers will be evaluated in the Real-Time market.

5.3 Thresholds for Identifying Economic Withholding.

5.3.1 Reserved.

5.3.2 Thresholds Applicable in Designated Congestion Areas. Pursuant to the procedures set forth in ***Exhibit 2***, from time to time, the ISO may establish one or more geographic areas in which the congestion is significant and competition is limited (a "Designated Congestion Area"). Thresholds to be employed by the ISO to identify economic withholding that may warrant the mitigation of a Resource in a Designated Congestion Area are set forth in ***Exhibit 2*** to this ***Appendix A***, and shall be determined with respect to a Reference Level determined as specified in Section 5.6, where appropriate. Resources in constrained areas that exceed the applicable thresholds and market impact tests and for which no sufficient explanation has been provided will be mitigated to the applicable Reference Level, determined in Section 5.6, unless an agreement has been negotiated under the procedures set forth in ***Exhibit 2***.

5.3.3 Thresholds Applicable in Other Congestion Areas. For a Resource located in a constrained area that is not a Designated Congestion Area, the following thresholds shall be employed by the ISO to identify economic withholding that may warrant Mitigation Measures. Offers exceeding these thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Reference Level determined as specified in Section 5.6, unless an agreement has been negotiated under the procedures set forth in ***Exhibit 2***.

(a) For Supply Offers for the Real-Time Market: for intervals in which a Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched ("Constrained Hours"), the ISO shall assess the market impact of any Supply Offers (Section 5.5.2(b)) that meet the following thresholds:

(i) Energy Offer Price – an increase of $25 or 50%, whichever is lower, above the Reference Level; or; or

(ii) Start-Up or No-Load Price – an increase of 50% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Market: for all Constrained Hours (as defined above) the ISO shall assess the market impact of any Supply Offers for the Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

5.4 Threshold for Identifying Uneconomic Production. In addition to the thresholds governing forms of economic withholding in Sections 5.3.2 and 5.3.3, the ISO will monitor for actions not consistent with competitive conduct involving uneconomic production. The following thresholds may warrant the imposition of a Mitigation Measure as provided in Section 5.7.4: (i) Energy scheduled at an LMP that is less than 20 % of the applicable Reference Level and causes or contributes to transmission congestion; or (ii) Real-Time output from a Resource that exceeds 110 % of the ISO's Dispatch Rate, and causes or contributes to transmission congestion.

5.5 Hourly Market Impact and Operating Reserve Thresholds.

5.5.1 Initial Investigation. Before imposing any Mitigation Measure as permitted in Section 5.7, with regard to offers and bids identified in accordance with Sections 5.3.2 or 5.3.3, and 5.4, the ISO shall investigate the reasons for the change in accordance with the applicable provisions of Section 3. If the offers and bids in question are not explained to the satisfaction of the ISO, the ISO, in consultation with the Independent Market Advisor, will determine whether the offers and bids in question would, if not mitigated, cause a material effect on the LMP at a Node, or clearing prices in the NEPOOL Markets or Operating Reserve charges as provided in Sections 5.5.2 and 5.5.3.

5.5.2 Market Impact Thresholds. Before a Mitigation Measure is imposed on offers exceeding the conduct thresholds, the ISO will determine whether there is an impact as follows:

(a) Reserved.

(b) For offers exceeding thresholds in Section 5.3.2, a material effect is one in excess of the threshold specified in ***Exhibit 2***, Section 2.4, or Operating Reserve payment thresholds as specified in ***Exhibit 1***, Section 2. For offers exceeding thresholds in Section 5.3.3, a material effect is one in excess of the conduct threshold specified in Section 5.3.3 above or Operating Reserve payment thresholds as specified in ***Exhibit 1***, Section 2.

5.5.3 Calculation of Price Impact.

(a) When it has the capability to do so, the Market Monitoring Unit, in consultation with the Independent Market Advisor, shall determine the effect on prices or Operating Reserve payments of questioned conduct through the use of sensitivity analyses performed using the ISO's unit dispatch system software ("UDS"), unit commitment software ("UCS"), scheduling, pricing and dispatch software ("SPD") and such other computer modeling or analytic methods as the ISO, in consultation with the Independent Market Advisor, shall deem appropriate.

(b) When a determination in accordance with paragraph (a) above is not practicable, including, but not limited to when market operations are being performed in the back-up control center during an Emergency, the ISO, in consultation with the Independent Market Advisor, shall determine the effect on prices or Operating Reserve payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. The price impact analysis will be performed to allow *ex ante* mitigation in the Day-Ahead Energy Market. *Ex ante* mitigation in the Real-Time Energy Market will be performed as soon as practicable.

(c) The Market Monitoring Unit may, in consultation with the Independent Market Advisor, set thresholds below which it need not apply the UDS, UCS, SPD, and other systems if it is reasonable to conclude that the market impact thresholds are not likely to be violated.

(d) In constrained areas, if appropriate models are not available as the result of limitations in hardware, software, or other technical difficulties, the ISO will manually evaluate the impact to determine if it is at least as large as the threshold value. If that is not practicable, then either of the following will be deemed to be a violation of the market impact screen for a constrained area Resource exceeding a conduct threshold specified in Section 5.3: (i) the scheduling of such

(b) The market impact thresholds described in Section 5.5 are exceeded.

5.7.3 Level of Default Offers. A substitute mitigated offer (a "Default Offer") shall be designed to cause a Participant to offer as if it faced workable competition during a period when (i) the Participant does not face workable competition, and (ii) has responded to such condition by engaging in the physical or economic withholding. In designing and implementing Default Offers, the ISO shall seek to avoid causing a Resource to offer below its marginal cost.

5.7.4 Implementation.

(a) The Default Offer may establish a mitigated value for one or more components of the offer for a given Resource equal to a Reference Level for that component of the Resource's offer determined as specified in Section 5.6.1.

(b) A Resource subject to a Default Offer shall be paid the LMP or other market clearing price applicable to the output from the Resource. Accordingly, a Default Offer shall not limit the price that a Resource may receive or pay unless the Default Offer determines the LMP or other market clearing price applicable to that Resource.

(c) Mitigation Measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

(d) When Mitigation Measures are applied to Offer Data, mitigation shall be imposed from the first hour in which the impact test is met to the last hour in which the impact test is met, or for the duration of the mitigated Resource's minimum run time, whichever is longer.

(e) The posting of the Day-Ahead schedule, rebidding period and reliability commitment run may be delayed if necessary for the completion of mitigation procedures.

(f) Mitigation that does not affect the LMP or a clearing price in another ISO market may be applied in the settlement process.

EXHIBIT 1

MARKET IMPACT AND OPERATING RESERVE THRESHOLDS

1. RESERVED

2. OPERATING RESERVE THRESHOLD

An increase of more than 100 % in Operating Reserve Credits due to the Participant facing mitigation in a dispatch day, provided that the increase also exceeds $10/MWh, compared to the Operating Reserve Credits calculated using Reference Levels as determined in Section 4.5 and the physical bid characteristics for the Resource. This calculation is as follows:

$$OR_e = \text{StartupPrice} + \sum_t [\text{NoLoadPrice}_t + (SE_t \times EBB_t) - (SE_t \times LMP_t)]$$

Where:

OR_e	=	Operating Reserve Energy Market Component
StartupPrice	=	Bid Startup Price (or Reference Level)
NoLoad Price	=	Bid No-Load Price (or Reference Level)
SE	=	Supplied Energy (or Reference Economic Minimum)
EBB	=	Energy Bid Block Prices (or Reference Levels)
LMP	=	Locational Marginal Price

t = Operating Hour of the Resource associated with one continuous start-up/dispatch period when Energy was Supplied (or as determined by Reference Characteristics)

The ISO, in consultation with the Independent Market Advisor, shall determine the effect of questioned conduct on Operating Reserve Charges using the best available data and such models and methods, as it deems appropriate.

Notwithstanding the foregoing, the ISO may determine additional RMR Congestion Areas at any time on an emergency basis or as the result of new or changed circumstances; with such prior notice and opportunity for comment as is practicable under the circumstances.

1.2 Mitigation of Resources Within Designated Congestion Areas. So long as Supply Offers for Resources within the Designated Congestion Area are below the applicable Designated Congestion Area Threshold, no other congestion area Mitigation Measures will apply. Offers exceeding the applicable Designated Congestion Area Threshold that fail the market impact threshold test specified in Section 2.4 of this ***Exhibit 2*** will be mitigated to the applicable Reference Level as provided in ***Appendix A***, Section 5.6. Notwithstanding the foregoing, Resources with Supply Offers and Reference Prices exceeding the Designated Congestion Area Threshold will only be evaluated for mitigation if they exceed the market impact threshold test specified in Section 2.4 of this ***Exhibit 2***.

2. DESIGNATED CONGESTION AREA THRESHOLD DETERMINATION

2.1 Threshold Calculation. Annually, or more frequently as the ISO deems necessary, the ISO will calculate a threshold for the upcoming 12 calendar months (the "Designated Congestion Area Threshold"). Supply Offers below the threshold will not be mitigated unless they violate the thresholds applicable in all areas, *e.g.,* Section 5.3.1 of ***Appendix A.*** The Designated Congestion Area Threshold will be calculated as follows:

$$\text{Designated Congestion Area Threshold} = \text{Incremental Proxy CT Operating Cost} + \frac{\text{Net Annual Fixed Cost}}{\text{Annual Constrained Hours}}$$

Where:

Incremental Proxy CT Operating Cost	=	Calculated as specified in 5.6.1(B)(iii) of ***Appendix A*** for a combustion turbine with a 10,500 heat rate, using a 3 month average of the 12 monthly forward gas prices plus transportation charges

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

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 are rights to receive FTR Auction Revenues as provided in Section 1. 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 in Attachments G and G-2 of the NEPOOL Tariff), using a four-stage process as described below (the "ARR Allocation").

2. FIRST STAGE ARR ALLOCATION

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 in Attachments G and G-2 of the NEPOOL 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 which 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. 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 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 2.2.

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 2.1 and in accordance with the NEPOOL Manuals and ISO Administrative Procedures prior to the first stage of the ARR Allocation for an FTR Auction.

APPENDIX E

LOAD RESPONSE PROGRAM

1. INTRODUCTION

1.1 Goal. The purpose of the Load Response Program ("LRP") is to facilitate load response during periods of peak electricity demand by providing appropriate incentives. Load Response Program incentives are available to any Participant or Non-Participant which, consistent with the requirements set forth herein, enrolls itself and/or one or more retail customers ("Demand Resources") to provide a reduction in their electricity consumption in the NEPOOL Control Area during peak demand periods. Non-Participants that wish to participate in the Load Response Program and have satisfied the applicable financial assurance criteria will be charged an annual service fee of $500. The service fee will be applied to ISO expenses and may be superceded by a future provision in the ISO Tariff.

1.2 Eligibility. The overall Load Response Program comprises the following individual components:

- Day-Ahead Demand Response Program
- Real-Time 30 Minute Demand Response Program
- Real-Time 2 Hour Demand Response Program
- Real-Time Price Response Program
- Real-Time Profiled Response Program

These programs are further defined in this Appendix E and the NEPOOL Manuals.

Demand Resources are only eligible to participate in one program at a time, except that a Demand Resource participating in the Day-Ahead Demand Response Program whose offer is not accepted in the Day-Ahead Energy Market, may participate in the Real-Time Price Response Program. Generating Resources that are already qualified as generating assets are not eligible to participate in the Load Response Program.

Any Demand Resource that is eligible to qualify as an ICAP Resource must be available, at a minimum, for the summer period (May 1 through September 30).

1.3 Effectiveness. The Load Response Program will be effective from the SMD Effective Date through February 28, 2006; except as provided in Section 2.1.

1.4 Allocation of Costs. The costs of Real-Time Load Response Programs will be allocated to the applicable Real-Time Load Obligation on a system wide basis (commencing on the SMD Effective Date), except for the costs associated with the Internet-based Communication System (IBCS) as provided in Section 7. Until the Day-Ahead program is implemented, Real-Time program costs will be allocated to Real-Time Load Obligation on a system wide basis (calculated by summing the Real-Time Load Obligation in each Load Zone). Commencing on the date that the Day-Ahead program is implemented, the allocation of the Load Response Program costs (except for IBCS costs provided in Section 7) will change from Load Obligation to Network Load on a system wide basis. To the extent that a program participant's bid in the Day-Ahead Demand Response Program clears (is accepted), any charges or credits associated with such deviations will be allocated to the program participant. The balancing credit or charge will be allocated to Network Load on a system wide basis. As stated in Section 2.1, the effective date for the Day-Ahead Demand Response Program will be the date specified by the ISO and posted on its website. Such date will be at least two weeks after the ISO has given the Commission written notice and has posted on its website that the NEPOOL System Rules and computer programs necessary to implement the Day-Ahead Demand Response Program are fully in place and functional.

1.5 General Requirements. A Demand Resource cannot span multiple Load Zones. A Price Response customer cannot span multiple Load Zones. All programs, except the Profiled Response Program, require interval metering. With the exception of the Profiled Response Program and "Super" Low-Tech option of the Real-Time Price Response Program, meters are read at least daily and some will require an Internet-based Communication System.

2. DAY-AHEAD DEMAND RESPONSE PROGRAM

Demand Resources that require more than 2 hours advance notice in order to curtail consumption may participate in the Day-Ahead Demand Response Program. Demand Resources with response times less than 2 hours may also participate in the Day-Ahead Demand Response Program. The Day-Ahead Demand Response Program is not intended to pay for load reductions that would have been scheduled in any event, such as facility shut-downs.

2.1 Effective Date. The Day-Ahead Demand Response Program will be effective as soon as practicable, but no earlier than the SMD Effective Date. The effective date for this program will be the date specified by the ISO and posted on its website. Such date will be at least two weeks after the ISO has given the Commission written notice that the NEPOOL System Rules and computer programs necessary to implement the Day-Ahead Demand Response Program are fully in place and functional and the ISO will post the date on its website at the time that the ISO makes such notice to the Commission.

2.2 Offer Parameters. A program participant may submit Supply Offers in the Day-Ahead Energy Market on behalf of a Demand Resource in increments of 1 MW or more. Resources may be aggregated to reach the 1 MW minimum. The minimum Supply Offer shall be $50/MWh and the maximum shall be $1,000/MWh. Demand Resources that participate in the Day-Ahead Demand Response Program are eligible to qualify as an ICAP Resource subject to the performance criteria identified within the NEPOOL Manuals.

2.3 Payment. Demand Resource Supply Offers that clear the Day-Ahead Energy Market will be paid the applicable Day-Ahead Zonal Price. To the extent a program participant's bid in Day-Ahead Demand Response Program clears (is accepted), and the participant's Real-Time load response deviates from its nominated response, any charges or credits associated with such deviations will be allocated to the program participant. The balancing credit or charge will be allocated to Network Load on a system wide basis. Data for calculating actual performance, including the base line and actual reductions shall be provided on a daily basis with other meter reading data.

3. REAL-TIME DEMAND RESPONSE PROGRAMS

3.1 General Terms. The Load Response Program includes two components that provide payments for Demand Resources that are willing and capable of responding to Real-Time ISO instructions to interrupt load within a specific time period. The minimum, aggregated size to participate in these programs is 100 kW.

3.1.1 Technical Requirements. Both the 30-Minute Demand Response and the 2-hour Demand Response Programs require the use of an Internet-based Communication System.

3.1.2 Program Activation. The ISO may issue interruption instructions to Demand Resources on a zonal or system wide (implemented in blocks) basis. The ISO may issue interruption instructions in blocks and not just by zone, to allow for a controlled implementation. A block is a system wide slice of the Demand Resources (approximately 200 MW per block).

3.2 30 Minute Demand Response Program. The 30 Minute Demand Response Program requires a Demand Resource to respond within 30 minutes of the ISO's instructions to interrupt.

3.3 Payment - 30 Minute Demand Response Program. Program participants receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of $500/MWh for a minimum of 2 hours. Demand Resources that participate in the 30 Minute Demand Response Program are eligible to qualify as an ICAP Resource, subject to the performance criteria identified in the NEPOOL Manuals.

3.4 2 Hour Demand Response Program. The 2 Hour Demand Response Program requires a Demand Resource to respond within 2 hours of the ISO's instructions to interrupt.

3.5 Payment - 2 Hour Demand Response Program. Program participants will receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of $350/MWh for a minimum of 2 hours. Demand Resources that participate in the 2 Hour Demand Response Program are eligible to qualify as an ICAP Resource, subject to the performance criteria identified in the NEPOOL Manuals.

ATTACHMENT 2

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

Table of Contents **Page**

1. PURPOSE AND OBJECTIVES 204
   1.1 Thresholds. 204
   1.2 Other Conduct. 204
2. MITIGATION PRINCIPLES 205
   2.1 Conduct Subject to Mitigation. 205
   2.2 Conditions for the Imposition of Mitigation Measures. 205
      2.2.1 Market Impact. 205
      2.2.2 Conduct Inconsistent with a Competitive Market. 205
   2.3 Categories of Conduct that May Warrant Mitigation. 205
      2.3.1 In General. 205
      2.3.2 Conduct Not Deemed Anti-Competitive. 206
      2.3.3 Physical Withholding by a Participant. 206
      2.3.4 Other Withholding of Supply Offers. 206
      2.3.5 Anti-Competitive Increment Offers and Decrement Bids. 206
      2.3.6 Other Conduct. 207
   2.4 Other Monitoring Objectives. 207
      2.4.1 Monitoring Targets. 207
      2.4.2 Reports. 208
   2.5 Further Changes. 208
   2.6 Duration of Mitigation Measures. 208
3. CONSULTATION REQUIREMENTS 209
   3.1 In General. 209
      3.1.1 ~~Notice and Opportunity to Respond~~Reserved. 209
      3.1.2 Consideration of Information in All Cases. 209
      3.1.3 Advance Consultation by Participant. 210
      3.1.4 Participant Access to Its Reference Levels. 210

Table of Contents **Page**

4. PHYSICAL WITHHOLDING....211
4.1 Identification of Conduct Inconsistent with Competition. 211
4.2 Thresholds for Identifying Physical Withholding....211
4.2.1 Initial Thresholds. 211
4.2.2 Adjustment to Generating Capacity....211
4.2.3 Withholding of Transmission. 212
4.2.4 Resources in Congestion Areas. 212
4.3 Hourly Market Impact and Operating Reserve Thresholds. 212
4.4 Imposition of Mitigation Measures....212
5. ECONOMIC WITHHOLDING AND UNECONOMIC PRODUCTION 213
5.1 Purpose....213
5.2 Applicability. 213
5.3 Thresholds for Identifying Economic Withholding. 213
5.3.1 General Thresholds....213
5.3.2 ~~Additional~~ Thresholds Applicable in Designated Congestion Areas. 214
5.3.3 ~~Additional~~ Thresholds Applicable in Other Congestion Areas. 214
5.4 Threshold for Identifying Uneconomic Production....215
5.5 Hourly Market Impact and Operating Reserve Thresholds. 215
5.5.1 Initial Investigation....215
5.5.2 ~~Market Impact Thresholds~~Reserved....215
5.5.3 Calculation of Price Impact....216
5.6 Calculation of Resource Reference Levels. 217
5.6.1 Methods for Determining Reference Levels. 217
5.6.2 Insufficient Data....218
5.7 Mitigation Measures....218
5.7.1 Manual Review Prior to Mitigation. 218
5.7.2 Conditions for Imposition of Mitigation Measures....218
5.7.3 Level of Default Offers....219
5.7.4 Implementation....219
6. RELIABILITY MUST-RUN AGREEMENTS 220
6.1 Mitigation Agreements. 220
6.2 Cost-of-Service Agreements....220
6.3 Filing with the Commission. 220
7. MITIGATION OF DEMAND BIDS....220

3. CONSULTATION REQUIREMENTS

3.1 In General. If through the application of an appropriate index or screen or other monitoring of market conditions, conduct is identified that (i) exceeds an applicable threshold, and (ii) has a material effect, as specified below, on one or more prices or Operating Reserve payments in the NEPOOL Market administered by the ISO, the ISO will take the steps set forth in this Section 3:

3.1.1 ~~Notice and Opportunity to Respond~~Reserved. ~~Before imposing mitigation for violation of general market thresholds (excluding thresholds regarding congestion mitigation),~~

~~(a) the ISO will, whenever practicable, contact the Participant engaging in the identified conduct to request an explanation of the conduct;~~

~~(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned conduct is consistent with competitive behavior, no further action will be taken; and~~

~~(c) The ISO will consider any information a Participant submits, but is not required to delay mitigation while waiting for information.~~

3.1.2 Consideration of Information in All Cases. In every case, the ISO will consider all available explanations of behavior that are based on a Participant's cost of providing any market product, including

(a) Any relevant opportunity costs,

(b) The need to shape bids and offers for a Limited Energy Resource to maximize the economic value from that Resource over time given the unique characteristics of the Resource, and

(c) any special price limitations applicable to dual-fuel resources.

5. ECONOMIC WITHHOLDING AND UNECONOMIC PRODUCTION

5.1 Purpose. This Section defines thresholds of economic withholding in ~~the unconstrained market and in~~ constrained areas. If conduct is detected that exceeds the thresholds specified in Sections 5.3 or 5.4 and the ISO determines that there is a market impact, as provided in Section 5.5, the conduct shall be remedied by the prospective application of a Default Offer as described in Section 5.7.

5.2 Applicability. Only Resources required to offer in the Day-Ahead market will be evaluated for economic withholding in the Day-Ahead market. All Supply Offers will be evaluated in the Real-Time market.

5.3 Thresholds for Identifying Economic Withholding.

5.3.1 ~~General Thresholds~~Reserved. ~~The ISO shall investigate the reasons for and market impact of any offers that exceed the following thresholds. Offers exceeding these thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Default Offer as determined in Section 5.7.~~

~~(a) *Energy Offer Price*. A 300 % increase or an increase of $100 per MWh above the Reference Level, whichever is lower, but excluding offers under $25;~~

~~(b) *Startup and No-load Offer Price*. A 200 % increase above the Reference Level.~~

~~(c) *Regulation Offers*. A 300 % increase or an increase of $25 per MW of Regulation above the Reference Level, whichever is lower, but excluding bids under $5.~~

~~(d) *Time Based Offer Parameters*. An increase greater than 2 hours in elements of a generation Resource's Offer Data that are expressed in time (e.g., minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based Offer Data compared to the unit's Reference Levels.~~

5.3.2 ~~**(e)** ***Offer Parameters Expressed Other than in Time or Dollars*. A 100 % increase for Offer Data that are minimum values, or a 50 % decrease for Offer Data that are maximum values (including, but not limited to, ramp rates and maximum starts per day).Additional**~~ **Thresholds Applicable in Designated Congestion Areas.** Pursuant to the procedures set forth in ***Exhibit 2***, from time to time, the ISO may establish one or more geographic areas in which the congestion is significant and competition is limited (a "Designated Congestion Area"). Thresholds ~~in addition to those set forth in Section 5.3.1~~ to be employed by the ISO to identify economic withholding that may warrant the mitigation of a Resource in a Designated Congestion Area are set forth in ***Exhibit 2*** to this ***Appendix A***, and shall be determined with respect to a Reference Level determined as specified in Section 5.6, where appropriate. Resources in constrained areas that exceed the applicable thresholds and market impact tests and for which no sufficient explanation has been provided will be mitigated to the applicable Reference Level, determined in Section 5.6, unless an agreement has been negotiated under the procedures set forth in ***Exhibit 2***. ~~The additional thresholds established in Exhibit 2 for Designated Congestion Areas shall be applied only when transmission constraints and demand conditions in the Designated Congestion Area require the dispatch of all capacity of all available resources within such area.~~

5.3.3 ~~**Additional**~~ **Thresholds Applicable in Other Congestion Areas.** ~~In addition to the thresholds set forth in Section 5.3.1, for~~For a Resource located in a constrained area that is not a Designated Congestion Area, the following thresholds shall be employed by the ISO to identify economic withholding that may warrant Mitigation Measures. Offers exceeding ~~both~~ these thresholds and market impact thresholds and for which no sufficient explanation has been provided, shall be mitigated to the Reference Level determined as specified in Section 5.6, unless an agreement has been negotiated under the procedures set forth in ***Exhibit 2***.

(a) For Supply Offers for the Real-Time Market: for intervals in which a Resource is dispatched for the purpose of relieving a transmission constraint above the level at which it otherwise would have been dispatched ("Constrained Hours"), the ISO shall assess the market impact of any Supply Offers (Section 5.5.2(b)) that meet the following thresholds:

(i) Energy Offer Price – an increase of $25 or 50%, whichever is lower, above the Reference Level; or; or

(ii) Start-Up or No-Load Price – an increase of 50% above the Reference Level.

(b) For Supply Offers for the Day-Ahead Market: for all Constrained Hours (as defined above) the ISO shall assess the market impact of any Supply Offers for the Resource that meet a threshold determined in accordance with the formula specified in subsection (a).

5.4 Threshold for Identifying Uneconomic Production. In addition to the thresholds governing forms of economic withholding in Sections ~~5.3.1, 5.3.2,~~5.3.2 and 5.3.3, the ISO will monitor for actions not consistent with competitive conduct involving uneconomic production. The following thresholds may warrant the imposition of a Mitigation Measure as provided in Section 5.7.4: (i) Energy scheduled at an LMP that is less than 20 % of the applicable Reference Level and causes or contributes to transmission congestion; or (ii) Real-Time output from a Resource that exceeds 110 % of the ISO's Dispatch Rate, and causes or contributes to transmission congestion.

5.5 Hourly Market Impact and Operating Reserve Thresholds.

5.5.1 Initial Investigation. Before imposing any Mitigation Measure as permitted in Section 5.7, with regard to offers and bids identified in accordance with Sections ~~5.3.1,~~ 5.3.2 or 5.3.3, and 5.4, the ISO shall investigate the reasons for the change in accordance with the applicable provisions of Section 3. If the offers and bids in question are not explained to the satisfaction of the ISO, the ISO, in consultation with the Independent Market Advisor, will determine whether the offers and bids in question would, if not mitigated, cause a material effect on the LMP at a Node, or clearing prices in the NEPOOL Markets or Operating Reserve charges as provided in Sections 5.5.2 and 5.5.3.

5.5.2 Market Impact Thresholds. Before a Mitigation Measure is imposed on offers exceeding the conduct thresholds, the ISO will determine whether there is an impact as follows:

(a) ~~For offers exceeding the thresholds in Section 5.3.1, a material effect is one in excess of either of the thresholds in ***Exhibit 1,*** Section 1.~~Reserved.

(b) For offers exceeding thresholds in Section 5.3.2, a material effect is one in excess of the threshold specified in ***Exhibit 2***, Section 2.4, or Operating Reserve payment thresholds as specified in ***Exhibit 1***, Section 2. For offers exceeding thresholds in Section 5.3.3, a material effect is one in excess of the conduct threshold specified in Section 5.3.3 above or Operating Reserve payment thresholds as specified in ***Exhibit 1***, Section 2.

5.5.3 Calculation of Price Impact.

(a) When it has the capability to do so, the Market Monitoring Unit, in consultation with the Independent Market Advisor, shall determine the effect on prices or Operating Reserve payments of questioned conduct through the use of sensitivity analyses performed using the ISO's unit dispatch system software ("UDS"), unit commitment software ("UCS"), scheduling, pricing and dispatch software ("SPD") and such other computer modeling or analytic methods as the ISO, in consultation with the Independent Market Advisor, shall deem appropriate.

(b) When a determination in accordance with paragraph (a) above is not practicable, including, but not limited to when market operations are being performed in the back-up control center during an Emergency, the ISO, in consultation with the Independent Market Advisor, shall determine the effect on prices or Operating Reserve payments of questioned conduct using the best available data and such models and methods as they shall deem appropriate. The price impact analysis will be performed to allow *ex ante* mitigation in the Day-Ahead Energy Market. *Ex ante* mitigation in the Real-Time Energy Market will be performed as soon as practicable.

(c) The Market Monitoring Unit may, in consultation with the Independent Market Advisor, set thresholds below which it need not apply the UDS, UCS, SPD, and other systems if it is reasonable to conclude that the market impact thresholds are not likely to be violated.

(d) In constrained areas, if appropriate models are not available as the result of limitations in hardware, software, or other technical difficulties, the ISO will manually evaluate the impact to determine if it is at least as large as the threshold value. If that is not practicable, then either of the following will be deemed to be a violation of the market impact screen for a constrained area Resource exceeding a conduct threshold specified in Section ~~5.3.1 or Section~~ 5.3: (i) the scheduling of such

(b) The market impact thresholds described in Section 5.5 are exceeded.

5.7.3 Level of Default Offers. A substitute mitigated offer (a "Default Offer") shall be designed to cause a Participant to offer as if it faced workable competition during a period when (i) the Participant does not face workable competition, and (ii) has responded to such condition by engaging in the physical or economic withholding. In designing and implementing Default Offers, the ISO shall seek to avoid causing a Resource to offer below its marginal cost.

5.7.4 Implementation.

(a) The Default Offer may establish a mitigated value for one or more components of the offer for a given Resource equal to a Reference Level for that component of the Resource's offer determined as specified in Section 5.6.1.

(b) A Resource subject to a Default Offer shall be paid the LMP or other market clearing price applicable to the output from the Resource. Accordingly, a Default Offer shall not limit the price that a Resource may receive or pay unless the Default Offer determines the LMP or other market clearing price applicable to that Resource.

(c) Mitigation Measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations or zones to rise over the entire day.

(d) When Mitigation Measures are applied to Offer Data~~ (as outlined in Section 5.3.1)~~, mitigation shall be imposed from the first hour in which the impact test is met to the last hour in which the impact test is met, or for the duration of the mitigated Resource's minimum run time, whichever is longer.

(e) The posting of the Day-Ahead schedule, rebidding period and reliability commitment run may be delayed if necessary for the completion of mitigation procedures.

(f) Mitigation that does not affect the LMP or a clearing price in another ISO market may be applied in the settlement process.

EXHIBIT 1

MARKET IMPACT AND OPERATING RESERVE THRESHOLDS

1. ~~Market Impact Threshold~~RESERVED

~~An increase of 200 % or $100 per MW, whichever is lower, in the LMP at a Node and 200 % or $25, whichever is lower, in any other NEPOOL market.~~

2. ~~Operating Reserve Threshold~~OPERATING RESERVE THRESHOLD

An increase of more than 100 % in Operating Reserve Credits due to the Participant facing mitigation in a dispatch day, provided that the increase also exceeds $10/MWh, compared to the Operating Reserve Credits calculated using Reference Levels as determined in Section 4.5 and the physical bid characteristics for the Resource. This calculation is as follows:

Where:

OR_e	=	Operating Reserve Energy Market Component
StartupPrice	=	Bid Startup Price (or Reference Level)
NoLoad Price	=	Bid No-Load Price (or Reference Level)
SE	=	Supplied Energy (or Reference Economic Minimum)
EBB	=	Energy Bid Block Prices (or Reference Levels)
LMP	=	Locational Marginal Price

t	=	Operating Hour of the Resource associated with one continuous start-up/dispatch period when Energy was Supplied (or as determined by Reference Characteristics)

The ISO, in consultation with the Independent Market Advisor, shall determine the effect of questioned conduct on ~~prices and~~ Operating Reserve Charges using the best available data and such models and methods, as it deems appropriate.

Notwithstanding the foregoing, the ISO may determine additional RMR Congestion Areas at any time on an emergency basis or as the result of new or changed circumstances; with such prior notice and opportunity for comment as is practicable under the circumstances.

1.2 Mitigation of Resources Within Designated Congestion Areas. ~~During conditions when the ISO requires the dispatch of all capacity of all available resources within a Designated Congestion Area, s~~So long as Supply Offers for Resources within the Designated Congestion Area are below the applicable Designated Congestion Area Threshold, no other congestion area Mitigation Measures will apply. Offers exceeding the applicable Designated Congestion Area Threshold that fail the market impact threshold test specified in Section 2.4 of this ***Exhibit 2*** will be mitigated to the applicable Reference Level as provided in ***Appendix A***, Section 5.6. Notwithstanding the foregoing, Resources with Supply Offers and Reference Prices exceeding the Designated Congestion Area Threshold will only be evaluated for mitigation if they exceed the market impact threshold test specified in Section 2.4 of this ***Exhibit 2***.

2. DESIGNATED CONGESTION AREA THRESHOLD DETERMINATION

2.1 Threshold Calculation. Annually, or more frequently as the ISO deems necessary, the ISO will calculate a threshold for the upcoming 12 calendar months (the "Designated Congestion Area Threshold"). Supply Offers below the threshold will not be mitigated unless they violate the thresholds applicable in all areas, *e.g.,* Section 5.3.1 of ***Appendix A.*** The Designated Congestion Area Threshold will be calculated as follows:

$$\text{Designated Congestion Area Threshold} = \text{Incremental Proxy CT Operating Cost} + \frac{\text{Net Annual Fixed Cost}}{\text{Annual Constrained Hours}}$$

Where:

Incremental Proxy CT Operating Cost	=	Calculated as specified in 5.6.1(B)(iii) of ***Appendix A*** for a combustion turbine with a 10,500 heat rate, using a 3 month average of the 12 monthly forward gas prices plus transportation charges

AUCTION REVENUE RIGHTS AND QUALIFIED UPGRADE AWARDS

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 are rights to receive FTR Auction Revenues as provided in Section 1. 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 in Attachments G and G-2 of the NEPOOL Tariff), using a four-stage process as described below (the "ARR Allocation").

2. FIRST STAGE ARR ALLOCATION

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 in Attachments G and G-2 of the NEPOOL 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 which 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. ~~The~~ If the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction ~~which is an External Transaction will retain its existing contract rights for physical scheduling of such transaction until such party elects~~does not elect to be allocated ARRs under ~~this~~ Section ~~2. Once~~2.1, then the ~~party responsible for paying the Congestion Cost~~ARRs associated with ~~energy purchased under~~ the destination Node(s) of the load served by such Excepted Transaction ~~which is an External Transaction elects to~~shall be allocated ~~ARRs, the party (i) will not be able to revert back to using their contract rights for physical scheduling; and (ii) may request to be allocated ARRs, prior to each FTR Auction, either pursuant to Section 2.1 or~~ pursuant to Section 2.2.

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 2.1 and in accordance with the NEPOOL Manuals and ISO Administrative Procedures prior to the first stage of the ARR Allocation for an FTR Auction.

APPENDIX E

LOAD RESPONSE PROGRAM

1. INTRODUCTION

1.1 Goal. The purpose of the Load Response Program ("LRP") is to facilitate load response during periods of peak electricity demand by providing appropriate incentives. Load Response Program incentives are available to any Participant or Non-Participant which, consistent with the requirements set forth herein, enrolls itself and/or one or more retail customers ("Demand Resources") to provide a reduction in their electricity consumption in the NEPOOL Control Area during peak demand periods. Non-Participants that wish to participate in the Load Response Program and have satisfied the applicable financial assurance criteria will be charged an annual service fee of $~~5,000.~~500. The service fee will be applied to ISO expenses and may be superceded by a future provision in the ISO Tariff.

1.2 Eligibility. The overall Load Response Program comprises the following individual components:

- Day-Ahead Demand Response Program
- Real-Time 30 Minute Demand Response Program
- Real-Time 2 Hour Demand Response Program
- Real-Time Price Response Program
- Real-Time Profiled Response Program

These programs are further defined in this Appendix E and the NEPOOL Manuals.

Demand Resources are only eligible to participate in one program at a time, except that a Demand Resource participating in the Day-Ahead Demand Response Program whose offer is not accepted in the Day-Ahead Energy Market, may participate in the Real-Time Price Response Program. Generating Resources that are already qualified as generating assets are not eligible to participate in the Load Response Program.

Any Demand Resource that is eligible to qualify as an ICAP Resource must be available, at a minimum, for the summer period (May 1 through September 30).

1.3 Effectiveness. The Load Response Program will be effective from the SMD Effective Date through ~~December 31, 2004~~February 28, 2006; except as provided in Section 2.1.

1.4 Allocation of Costs. The costs of ~~the~~Real-Time Load Response Programs will be allocated to the applicable Real-Time Load Obligation on a ~~Load~~system ~~Zone~~wide basis (commencing on the SMD Effective Date), except for the costs associated with the Internet-based Communication System (IBCS) as provided in Section 7. Until the Day-Ahead program is implemented, Real-Time program costs will be allocated to Real-Time Load Obligation on a system wide basis (calculated by summing the Real-Time Load Obligation in each Load Zone). Commencing on the date that the Day-Ahead program is implemented, the allocation of the Load Response Program costs (except for IBCS costs provided in Section 7) will change from Load Obligation ~~on a Load Zone basis~~ to Network Load on a ~~Load~~system ~~Zone~~wide basis. To the extent that a program participant's bid in the Day-Ahead Demand Response Program clears (is accepted), any charges or credits associated with such deviations will be allocated to the program participant. The balancing credit or charge will be allocated to Network Load on a ~~Load~~system ~~Zone~~wide basis. As stated in Section 2.1, the effective date for the Day-Ahead Demand Response Program will be the date specified by the ISO and posted on its website. Such date will be at least two weeks after the ISO has given the Commission written notice and has posted on its website that the NEPOOL System Rules and computer programs necessary to implement the Day-Ahead Demand Response Program are fully in place and functional.

1.5 General Requirements. A Demand Resource cannot span multiple Load Zones. A Price Response customer cannot span multiple Load Zones. All programs, except the Profiled Response Program, require interval metering. With the exception of the Profiled Response Program and "Super" Low-Tech option of the Real-Time Price Response Program, meters are read at least daily and some will require an Internet-based Communication System.

2. DAY-AHEAD DEMAND RESPONSE PROGRAM

Demand Resources that require more than 2 hours advance notice in order to curtail consumption may participate in the Day-Ahead Demand Response Program. Demand Resources with response times less than 2 hours may also participate in the Day-Ahead Demand Response Program. The Day-Ahead Demand Response Program is not intended to pay for load reductions that would have been scheduled in any event, such as facility shut-downs.

2.1 Effective Date. The Day-Ahead Demand Response Program will be effective as soon as practicable, but no earlier than the SMD Effective Date. The effective date for this program will be the date specified by the ISO and posted on its website. Such date will be at least two weeks after the ISO has given the Commission written notice that the NEPOOL System Rules and computer programs necessary to implement the Day-Ahead Demand Response Program are fully in place and functional and the ISO will post the date on its website at the time that the ISO makes such notice to the Commission.

2.2 Offer Parameters. A program participant may submit Supply Offers in the Day-Ahead Energy Market on behalf of a Demand Resource in increments of 1 MW or more. Resources may be aggregated to reach the 1 MW minimum. The minimum Supply Offer shall be $50/MWh and the maximum shall be $~~500~~1,000/MWh. Demand Resources that participate in the Day-Ahead Demand Response Program are eligible to qualify as an ICAP Resource subject to the performance criteria identified within the NEPOOL Manuals.

2.3 Payment. Demand Resource Supply Offers that clear the Day-Ahead Energy Market will be paid the applicable Day-Ahead Zonal Price. To the extent a program participant's bid in Day-Ahead Demand Response Program clears (is accepted), and the participant's Real-Time load response deviates from its nominated response, any charges or credits associated with such deviations will be allocated to the program participant. The balancing credit or charge will be allocated to Network Load on a ~~Load Zone~~system wide basis. Data for calculating actual performance, including the base line and actual reductions shall be provided on a daily basis with other meter reading data.

3. REAL-TIME DEMAND RESPONSE PROGRAMS

3.1 General Terms. The Load Response Program includes two components that provide payments for Demand Resources that are willing and capable of responding to Real-Time ISO instructions to interrupt load within a specific time period. The minimum, aggregated size to participate in these programs is 100 kW.

3.1.1 Technical Requirements. Both the 30-Minute Demand Response and the 2-hour Demand Response Programs require the use of an Internet-based Communication System.

3.1.2 Program Activation. The ISO may issue interruption instructions to Demand Resources on a zonal or system wide (implemented in blocks) basis. The ISO may issue interruption instructions in blocks and not just by zone, to allow for a controlled implementation. A block is a system wide slice of the Demand Resources (approximately 200 MW per block).

3.2 30 Minute Demand Response Program. The 30 Minute Demand Response Program requires a Demand Resource to respond within 30 minutes of the ISO's instructions to interrupt.

3.3 Payment - 30 Minute Demand Response Program. Program participants receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of $~~150~~500/MWh for a minimum of 2 hours. Demand Resources that participate in the 30 Minute Demand Response Program are eligible to qualify as an ICAP Resource, subject to the performance criteria identified in the NEPOOL Manuals.

3.4 2 Hour Demand Response Program. The 2 Hour Demand Response Program requires a Demand Resource to respond within 2 hours of the ISO's instructions to interrupt.

3.5 Payment - 2 Hour Demand Response Program. Program participants will receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of $~~100~~350/MWh for a minimum of 2 hours. Demand Resources that participate in the 2 Hour Demand Response Program are eligible to qualify as an ICAP Resource, subject to the performance criteria identified in the NEPOOL Manuals.

ATTACHMENT 3

ATTACHMENT 3
CLARIFICATION OF TERMS

<u>I. Clarify the difference between Real-Time Load Obligation Deviation and Real-Time Adjusted Load Obligation Deviation.</u>

General Information

- The definitions of these quantities can be referenced in section 3.2.1 of Market Rule 1.
- The quantities discussed below; Day-Ahead Load Obligation, Real-Time Load Obligation, Day-Ahead Adjusted Load Obligation, Real-Time Adjusted Load Obligation, Real-Time Load Obligation Deviation, and Real-Time Adjusted Load Obligation Deviation, are all expressed in MWh and are calculated for each Participant at each location (node, zone, hub) for each hour.

Real-Time Load Obligation Deviation – The Real-Time Load Obligation Deviation at a location is the algebraic difference between the Participant's Real-Time Load Obligation (RTLO) and Day-Ahead Load Obligation (DALO) at that location where:

<u>Real-Time Load Obligation</u> = Revenue Metered Load (which represents the physical energy serving obligation of the Participant absent any bilateral activity)

+ Scheduled Exports

+ Internal Bilateral for Load Sales (which represent the assumption of physical energy serving obligations from another Participant)

- Internal Bilateral for Load Purchases (which represent the transfer of physical energy serving obligations to another Participant)

<u>Day-Ahead Load Obligation</u> = Cleared Demand bids
+ Cleared Decrements Bids
+ Cleared Exports

The Real-Time Load Obligation (RTLO) is the sum of the RT physical energy serving obligations of the Participant. Combining the metered load with any external obligations and then netting any Internal Bilaterals for Load yields the RTLO. The Day-Ahead Load Obligation (DALO) is the sum of the DA cleared energy obligations of the Participant. Combining the cleared Demand and Decrement bids with Day-Ahead external obligations yields the DALO. Internal Bilaterals for Load (IBLs) are not available in the Day-Ahead market.

Real-Time Adjusted Load Obligation Deviation – The Real-Time Adjusted Load Obligation Deviation at a location is the algebraic difference between the Participant's Real-Time Adjusted Load Obligation (RTALO) and Day-Ahead Adjusted Load Obligation (DAALO) at that location where:

<u>Real-Time Adjusted Load Obligation</u> **=** Real-Time Load Obligation
+ Internal Bilateral for Market (Energy) Sales (which represent the transfer of a specific quantity of energy to a Participant)
- Internal Bilateral for Market (Energy) Purchases (which represent the acquisition of a specific quantity of energy from a Participant)

<u>Day-Ahead Adjusted Load Obligation</u> **=** Day-Ahead Load Obligation
+ Internal Bilateral for Market (Energy) Sales (which represent the transfer of a specific quantity of energy to a Participant)
- Internal Bilateral for Market (Energy) Purchases (which represent the acquisition of a specific quantity of energy from a Participant)

<u>By looking at the equations, we can see the only difference between the Real-Time Load Obligation and Real-Time Adjusted Load Obligation terms is the inclusion of Internal Bilateral for Market (Energy) transactions</u>

<u>II. Distinguish between Internal Bilateral for Load and Internal Bilateral for Market (Energy)</u>

Internal Bilateral for Load (IBL) – For the purposes of Energy Market accounting, An IBL will increase or decrease the energy serving obligations of the two Participants involved in the transaction. IBLs do not impact the physical dispatch of the power system and are reflected only in the settlement process. An IBL can only be used in the Real-Time Market. In addition to their impact on Energy Market positions, IBLs impact the Regulation market positions of both parties and, under current rules, shift responsibility for Operating Reserve charges from the buyer to the seller.

Internal Bilateral for Market (IBM) – An IBM transfers the rights to a specific quantity of a specified Market product between two Participants. They are equivalent to system contracts in New England's existing market and are not associated with a specific resource. IBMs do not impact the physical dispatch of the power system and are reflected only in the settlement process. An IBM will only affect the market for which the transaction was submitted. An IBM for Energy will only affect the Participant's position in the Energy Market and not the Regulation or ICAP Market. A Participant's may submit three separate transactions, one to cover each Market, if it wants to cover all products. In the Day-Ahead Market only the IBM for Energy can be used. An IBM for Regulation is only available in the Real-Time market and the ICAP IBM can only be used for ICAP. IBMs currently have no impact on the Operating Reserve charge allocation.

The table below indicates the markets impacted by each type of bilateral transaction. Note that Day-Ahead IBMs for Energy are shown as having an impact in the Real-Time markets. This is because, under the current rules, a Day-Ahead IBM for Energy is automatically carried forward as a Real-Time IBM for Energy.

Type	**Product**	**DA Energy**	**RT Energy**	**RT Regulation**	**RT Operating Reserve Charges**	**Monthly ICAP**
IBM	Energy (DA)	X	X			
IBM	Energy (RT)		X			
IBM	Regulation			X		
IBM	ICAP					X
IBL			X	X	X	

ATTACHMENT 4

ATTACHMENT 4

NEPOOL PARTICIPANTS COMMITTEE
VOTING RESULTS
January 10, 2003

SECTOR	VOTE 1	VOTE 2	VOTE 3
GENERATION	0.00	15.00	16.00
TRANSMISSION	8.57	20.00	0.00
SUPPLIER	8.57	15.56	18.57
PUBLICLY OWNED ENTITY	20.00	20.00	10.00
END USER	4.29	20.00	0.00
% IN FAVOR	**41.43**	**90.56**	**44.57**
	41.43	90.56	44.57
	100.00	100.00	100.00
	0.00	0.00	0.00

GENERATION SECTOR

ATTACHMENT 4

	Participant Name	Vote 1	Vote 2	Vote 3
1	ANP Marketing			
1	Duke Energy North America LLC			
1	Entergy Nuclear Generation Company	O	A	F
1	FPL Energy LLC	O	F	O
1	Generation Group Member	O	O	F
1	Mirant New England, LLC	O	F	F
1	TransCanada Power Marketing Ltd.	A	F	F
7				
	IN FAVOR (F)	0	3	4
	OPPOSED (O)	4	1	1
	TOTAL VOTES	4	4	5
	ABSTENTIONS (A)	1	1	0
	ALL VOTES	5	5	5
	QUORUM IN ATTENDANCE	Y	Y	Y
	SECTOR QUORUM	3		
	MEMBER FIXED VOTING SHARE	2.857		
	UNADJUSTED SECTOR VOTING SHARE	0	15	16
	ADJUSTED SECTOR VOTING SHARE	0	15	16
	SVS/SUM MFVS	20	20	20

TRANSMISSION SECTOR

	Participant Name	Vote 1	Vote 2	Vote 3
1	Bangor Hydro-Electric Company	O	F	
1	Boston Edison Company	O	F	O
1	Central Maine Power Company	F	F	O
1	New England Power Company	O	F	O
1	Northeast Utilities Service Company	F	A	O
1	The United Illuminating Company	O	F	O
1	Vermont Electric Power Company, Inc.	F	F	O
7				
	IN FAVOR (F)	3	6	0
	OPPOSED (O)	4	0	6
	TOTAL VOTES	7	6	6
	ABSTENTIONS (A)	0	1	0
	ALL VOTES	7	7	6
	QUORUM IN ATTENDANCE	Y	Y	Y
	SECTOR QUORUM	3		
	MEMBER FIXED VOTING SHARE	2.857		
	SECTOR VOTING SHARE	8.57	20.00	0.00
	ADJUSTED SECTOR VOTING SHARE	8.571428571	20	0
	SVS/SUM MFVS	20.00	20.00	20.00

SUPPLIER SECTOR

	Participant Name	Vote 1	Vote 2	Vote 3
1	AES Londonderry	A	F	F
1	AIG Energy Trading Inc.			
1	Allegheny Energy Supply Company			
1	Allied Utility Network LLC			
1	American Electric Power Service Corp.			
1	Aquila Merchant Services			
1	BP Energy Company			
1	Brascan Energy Marketing Inc.			
1	Calpine Energy Services, L.P.	A	F	F
1	Cargill Power Markets, LLC			
1	CinCap V, LLC			
1	Citadel Energy Products LLC			
1	Conectiv Energy Supply, Inc.			
1	Consolidated Edison Energy, Inc.	A	F	
1	Constellation Power Source, Inc.	O	F	O
1	Coral Power, LLC	A	A	F
1	DTE Energy Trading, Inc.			
1	Dynegy (f/k/a Electric Clearing House, Inc.)			
1	Edison Mission Marketing and Trading			
1	El Paso Merchant Energy, LP	O	A	F
1	Energy America, LLC			
1	Energy Atlantic, LLC			
1	Exelon Generation Company, LLC	A	A	F
1	Great Bay Power Marketing, Inc.			
1	Hess Energy Power & Gas Company, LLC			
1	H.Q. Energy Services (U.S.) Inc.	O	A	F
1	Indeck-Pepperell Power Associates, Inc.	A	A	F
1	J. Aron & Company			
1	LIPA	A	A	F
1	Morgan Stanley Capital Group, Inc.			
1	NRG Power Marketing, Inc.	A	A	F
1	PG&E Energy Trading	F	A	F
1	PPL EnergyPlus, LLC			
1	Providence Energy Services, Inc.			
1	PSEG Energy Resources & Trade LLC	A	F	F
1	Reliant Energy Services, Inc.			
1	RWE Trading Americas Inc.			
1	Sempra Energy Trading Corp.	A	F	A
1	SmartEnergy.com, Inc.			
1	Sprague Energy Corp.			
1	Strategic Energy Ltd.	F	O	A
1	Tractebel Energy Marketing, Inc.			
1	TransAlta Energy Marketing (U.S.) Inc.			
1	TXU Energy Trading Company LP			
1	UAE Lowell Power LLC	A	A	F
1	UBS AG			
1	Unitil Corporation Participant Companies	O	F	
1	Virginia Electric and Power Company	F	O	F
1	Williams Energy Marketing & Trading Co.			
1	WPS Energy Services Inc.			
50				
	IN FAVOR (F)	3	7	13
	OPPOSED (O)	4	2	1
	TOTAL VOTES	7	9	14
	ABSTENTIONS (A)	11	9	2
	ALL VOTES	18	18	16
	QUORUM IN ATTENDANCE	Y	Y	Y

PUBLICLY OWNED ENTITY SECTOR

ATTACHMENT 4

	Participant Name	Vote 1	Vote 2	Vote 3
1	Ashburnham Municipal Light Plant	F	F	F
1	Belmont Municipal Light Department	F	F	F
1	Boylston Municipal Light Department	F	F	F
1	Braintree Electric Light Department	F	F	F
1	Chicopee Municipal Lighting Plant	F	F	F
1	Concord Municipal Light Plant	F	F	F
1	Conn. Municipal Electric Energy Cooperative	F	F	F
1	Danvers Electric Division	F	F	F
1	Georgetown Municipal Light Department	F	F	F
1	Groton Electric Light Department	F	F	F
1	Hingham Municipal Lighting Plant	F	F	F
1	Holden Municipal Light Department	F	F	F
1	Holyoke Gas & Electric Department	F	F	F
1	Hudson Light and Power Department	F	F	F
1	Hull Municipal Lighting Plant	F	F	F
1	Ipswich Municipal Light Department	F	F	F
1	Littleton Electric Light Department	F	F	F
1	Mansfield Municipal Electric Department	F	F	F
1	Marblehead Municipal Light Department	F	F	F
1	Mass. Municipal Wholesale Electric Company	F	F	F
1	Middleborough Gas and Electric Department	F	F	F
1	Middleton Municipal Electric Department	F	F	F
1	New Hampshire Electric Cooperative, Inc.	F	F	F
1	North Attleborough Electric Department	F	F	F
1	Norwood Municipal Light Department			
1	Pascoag Utility District	F	F	F
1	Paxton Municipal Light Department	F	F	F
1	Peabody Municipal Light Plant	F	F	F
1	Reading Municipal Light Department			
1	Rowley Municipal Lighting Plant	F	F	F
1	Shrewsbury's Electric Light Plant	F	F	F
1	South Hadley Electric Light Department	F	F	F
1	Sterling Municipal Electric Light Department	F	F	F
1	Taunton Municipal Lighting Plant	F	F	F
1	Templeton Municipal Lighting Plant	F	F	F
1	Vermont Public Power Supply Authority	F	F	F
1	Wakefield Municipal Gas and Light Department	F	F	F
1	Wellesley Municipal Light Plant			
1	West Boylston Municipal Lighting Plant	F	F	F
1	Westfield Gas & Electric Light Department	F	F	F
40				
	IN FAVOR (F)	37	37	37
	OPPOSED (O)	0	0	37
	TOTAL VOTES	37	37	74
	ABSTENTIONS (A)	0	0	0
	ALL VOTES	37	37	74
	QUORUM IN ATTENDANCE	Y	Y	Y
	SECTOR QUORUM	3		

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END USER SECTOR

ATTACHMENT 4

	Participant Name	Vote 1	Vote 2	Vote 3
1	Associated Industries of Massachusetts (O)	O	F	O
1	Cape Light Compact, The (O)			
1	Connecticut, State of, Office of Consumer Counsel (O)	O	F	O
1	Energy Management Inc. (S)			
1	Forster, Inc. (S)	O	F	O
1	Gardiner Paperboard (L)	O	F	O
1	Industrial Energy Consumer Group (O)	O	F	O
1	J.F. Gray & Associates, LLC (S)			
1	LaPorta, Leonard (S)			
1	Maine Health & Higher Educ. Fac. Authority, The (O)			
1	Maine Skiing, Inc. (O)	O	F	O
1	Maine, State of, Office of the Governor (O)	A	F	A
1	Mass. Energy Buyers Coalition (MEBC) (O)			
1	Mass. Public Interest Research Group (MASSPIRG) (O)	F		
1	McLaughlin Trust, Robert E. (S)			
1	Mead Oxford Corporation (S)	O	F	O
1	New Hampshire Office of Consumer Advocate (O)	F	A*	O
1	PowerOptions, Inc. (O)			
1	Praxair, Inc. (L)	O	F	O
1	Schaefer, Marc (S)			
1	Silkman, Richard (S)			
1	Texas Instruments (L)	O	F	O
1	The Energy Consortium (O)	O	F	O
1	The Energy Council of Rhode Island (TEC-RI) (O)	O	F	O
1	Union of Concerned Scientists (O)	F	F	O
1	WebGen Systems, Inc. (S)			
26				
	*NHOCA subsequently requested to abstain which does not effect the final results.			
	IN FAVOR (F)	3	13	0
	OPPOSED (O)	11	0	13
	TOTAL VOTES	14	13	13
	ABSTENTIONS (A)	1	1	1
	ALL VOTES	15	14	14
	QUORUM IN ATTENDANCE	Y	Y	Y
	SECTOR QUORUM	3		
	MEMBER FIXED VOTING SHARE	0.769		
	SECTOR VOTING SHARE	4.29	20.00	0.00
	ADJUSTED SECTOR VOTING SHARE	4.285714286	20	0
	SVS/SUM MFVS	20.00	20.00	20.00

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ATTACHMENT 6

New England Governors
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Rhode Island

The Honorable Donald Carcieri State House Rm. 143 Providence, RI 02903	Rhode Island Public Utilities Commission 89 Jefferson Boulevard Warwick, RI 02888

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ATTACHMENT 7

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool and ISO New England Inc.,) Docket No. ER02-2330-___

NOTICE OF FILING

(January , 2003)

Take notice that on January 21, 2003, the New England Power Pool ("NEPOOL") Participants Committee and ISO New England Inc., ("ISO-NE") submitted their Report of Compliance in response to the requirements of the Commission's December 20, 2002 order in New England Power Pool, 101 FERC ¶ 61,344 (2002).

The Participants Committee states that copies of these materials were sent to the New England state governors and regulatory commissions and the Participants in NEPOOL.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov, using the "FERRIS" link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll-free at (866)208-3676, or for TTY, contact (202)502-8659. Protests and interventions may be filed electronically via the Internet in lieu of paper; see 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link. The Commission strongly encourages electronic filings.

Comment Date: February , 2003

Magalie Roman Salas
Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Hartford, Connecticut this 21st day of January, 2003.

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