October 23, 2009

VIA HAND DELIVERY

The Honorable Kimberly D. Bose, Secretary
The Honorable Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
Room 1A-East, First Floor
888 First Street, N.E.
Washington, D.C. 20426

Re: ISO New England Inc. and New England Power Pool, Docket No. ER10-____-000
Revised Reserve Constraint Penalty Factor for Thirty-Minute Operating Reserve

Dear Ms. Bose and Mr. Davis:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO") and the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties") hereby submit to the Federal Energy Regulatory Commission ("Commission") a market rule revision (the "Rule Revision") relating to the Reserve Constraint Penalty Factor (sometimes referred to as "RCPF") for Thirty-Minute Operating Reserves ("TMOR"). Specifically, the Rule Revision increases the value of the RCPF for TMOR that applies to import-constrained Reserve Zones from \$50/MWh to \$250/MWh. The Rule Revision allows the real-time market system to economically dispatch resources to maintain the TMOR requirement in import-constrained Reserve Zones under a broader set of conditions, reducing the need for manual operator intervention. As a result, revising the RCPF increases the efficiency of dispatch and pricing and reduces the congestion costs incurred to maintain local reserves.

The Filing Parties request an effective date for the Rule Revision on or after January 1, 2010, subject to the provision of at least two-week advance notice by the ISO. In support of the Rule Revision, the ISO provides herewith the Prepared Testimony of Marc D. Montalvo, Director, Market Development, with ISO New England Inc. ("Montalvo Testimony"), which is Attachment 3 to this letter. The ISO also is providing an affidavit in support of the Rule Revision prepared by Pallas Lee Van Schaick, PhD, of the ISO's Independent Market Monitoring Unit (the "IMMU Affidavit"), which is Attachment 4 to this letter.

[1] 16 U.S.C. § 824d (2000).

[2] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff (FERC Electric Tariff No. 3) (the "Tariff"). Section III of the Tariff is Market Rule 1.

I. REQUESTED EFFECTIVE DATE AND REQUEST FOR WAIVER

The Filing Parties request an effective date on or after January 1, 2010, with two weeks' prior notice to be provided by the ISO for the actual effective date. The ISO currently expects to be able to implement the Rule Revision on January 1, 2010. However, it is possible that the implementation process could take longer than expected. Pursuant to Section 35.3(a), all rate schedules or any part thereof must be filed with the Commission and posted not "more than one hundred-twenty days prior to the date on which the electric service is to commence and become effective." Since it is possible that the Rule Revision could become effective more than one hundred-twenty days after the date of this filing, the Filing Parties request, to the extent necessary, waiver of the provisions of Section 35.3(a)(1) of the Commission's rules and regulations to permit the requested effective date for the Rule Revision. There is good cause to permit the requested waiver as it will ensure that the Rule Revision becomes effective in an orderly and transparent manner.

The Filing Parties do not request that the Commission issue an order on an expedited basis in this proceeding. Given the changes sought herein, a Commission order in the normal course of business (*i.e.*, prior to the 60th day following the date of this filing) is respectfully requested.

II. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO New England Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 410 members. The participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, developers, demand resource providers, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[3] the participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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III. STANDARD OF REVIEW

The ISO submits these revisions pursuant to Section 205 of the FPA, which "gives a utility the right to file rates and terms for services rendered with its assets."[5] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[6] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[7] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate

[4] Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

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

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

[7] *Id.* at 9.

schedule is more or less reasonable than alternative rate designs."[8] The changes filed herein "need not be the only reasonable methodology, or even the most accurate."[9] As a result, even if an intervenor or the Commission develops an alternate proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[10]

IV. DISCUSSION OF THE REVISED RCPF VALUE FOR TMOR

By way of background, the ISO schedules resources to provide energy and reserves via a co-optimized market-clearing system.[11] The co-optimization process produces real-time prices and scheduled quantities based on the submitted offer data and real-time operational constraints, including system and local reserve requirements and transmission constraints.[12] When there is sufficient reserve supply (no reserve shortage or energy re-dispatch), reserve prices are zero.[13] When reserve constraints bind, the reserve clearing price will be positive, reflecting the opportunity cost of resources re-dispatched to provide reserves.[14] Reserve clearing prices are capped at the value of the applicable Reserve Constraint Penalty Factor, or RCPF, for each type of reserve. The current value of the RCPF for Thirty Minute Operating Reserve, or TMOR, for each of the three local reserve zones in New England (comprised of NEMA/Boston, Connecticut and Southwest Connecticut) is $50/MWh.[15] The Rule Revision would increase the RCPF for TMOR for the local reserve zones to $250/MWh.[16]

The purpose of increasing the RCPF for TMOR is to achieve a better balance between (1) protecting against market power abuse and (2) the benefit of allowing the market-clearing system to efficiently re-dispatch resources to provide reserves. As discussed below, and in the Montalvo Testimony and IMMU Affidavit, the increased value of the RCPF for TMOR more optimally reaches this balance and should continue to protect against market power abuse and should result in more efficient dispatch of resources in real time.[17]

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[8] *Cities of Bethany, Bushnell et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984) ("*Cities of Bethany*"); *see also ISO New England Inc.*, 114 FERC ¶ 61,315 at P 33 and n.35 (2005), citing *Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987) and *Cities of Bethany* at 1136.

[9] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (citing *Cities of Bethany* at 1136).

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

[11] Montalvo Testimony at 2.

[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] *Id.* at 3.

[16] *Id.*

[17] Montalvo Testimony at 5; IMMU Affidavit at P 5.

RCPF values determine how the co-optimized market-clearing system schedules resources and establishes prices during operating conditions when there is relative scarcity of reserves.[18] When it is not possible to meet the reserve requirements, the RCPFs prevent the market-clearing system from incurring extraordinary costs for little or no reliability benefit. However, if the local RCPF is not sufficiently high, the market-clearing system does not schedule all available economic resources in the local area to meet the reliability requirements.[19] In this case, if sufficient capacity is available to maintain reserves, a system operator intervenes to maintain reserves, manually scheduling generators or binding the second contingency proxy transmission constraint, resulting in a less efficient allocation of resources and distorting real-time market-clearing prices.[20] In both its 2007 and 2008 annual market assessments, the Independent Market Monitoring Unit ("IMMU") determined that the existing $50/MWh value of the RCPF for TMOR had resulted in a less efficient allocation of resources in New England. Specifically, the IMMU indicated that "actions taken by the ISO to maintain local reserves are often more costly than the RCPF, which indicates that the RCPF may be set inefficiently low."[21]

As explained more fully in the Montalvo Testimony, the ISO conducted an analysis to determine a more appropriate value for the RCPF for TMOR.[22] Based on that analysis, the ISO determined that the appropriate local value for the RCPF for TMOR should be $250/MWh. The $250/MWh RCPF value approximates the difference between the hub price and the cost of the typical local marginal units which are chosen to be dispatched under constrained operating conditions.[23] The $250/MWh RCPF value also reflects a more realistic re-dispatch cost for procuring the local TMOR when reserves are scarce. At this level, the system can economically dispatch resources to maintain the TMOR requirement in the local area without frequent market interventions by the control operators.[24]

Importantly, as discussed in the IMMU Affidavit, the change in the RCPF for TMOR generally should not enhance market power in local reserve zones in New England.[25] In the case of increasing the RCPF for TMOR to $250/MWh, the IMMU finds that the incentives for suppliers to seek to artificially reduce supply in order to raise energy-clearing prices above competitive levels are the same or lower than they would otherwise be.[26] The IMMU notes that the revised RCPF value can result in somewhat increased incentives to withhold supply to

[18] Montalvo Testimony at 3.

[19] *Id.* at 4.

[20] *Id.*

[21] Independent Market Monitoring Unit for ISO New England Inc., 2008 Assessment of the Electricity Markets in New England (June 2009), at Executive Summary, p. xiii (available at http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2008_immu_report_final.pdf).

[22] Montalvo Testimony at 4-5.

[23] *Id.* at 8.

[24] *Id.* at 11.

[25] IMMU Affidavit at PP 14-21.

[26] *Id.* at PP 17-21.

influence reserve prices. This concern, however, is diminished because the majority of local reserves are provided by generators with forward reserve obligations that are paid according to the clearing price in the forward reserve auction rather than in the real-time market.[27]

The IMMU Affidavit also notes that the ISO administers market power mitigation measures that are effective in limiting the exercise of market power in areas that are constrained due to local reserve requirements.[28] The mitigation measures generally address any economic and physical withholding that could result in substantial increases in LMPs or reserve clearing prices. The mitigation measures work by replacing the offers submitted by suppliers with reference levels if the offers violate certain conduct and market impact thresholds.[29] The IMMU concludes that these mitigation measures further protect against the exercise of market power in local reserve zones that might be associated with increasing the level of the RCPF for TMOR.[30]

V. STAKEHOLDER PROCESS

The Markets Committee considered and discussed the Rule Revision over the course of three meetings during the May 2009 to July 2009 timeframe. At its July 14-15, 2009 meeting, the Markets Committee voted 96.57% in favor with 20 abstentions to recommend support for the Rule Revision to the Participants Committee.[31] The Participants Committee, at its August 7, 2009 meeting, voted to support the Rule Revision as part of its Consent Agenda.[32]

VI. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[33] However, the Rule Changes are not traditional "rates." Further, the Filing Parties are not traditional investor-owned utilities. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations. Notwithstanding their request for

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[27] *Id.* at P 21.

[28] *Id.* at P 22.

[29] *Id.* at P 23.

[30] *Id.* at P 25.

[31] There were four abstentions in the Generation sector, three abstentions in the Transmission sector, three abstentions in the Supplier sector, four abstentions in the Alternative Resource sector, and six abstentions in the End User sector. The only opposition was in the Supplier sector.

[32] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's approval of the August 7, 2009 Consent Agenda included its support for the Rule Revision. While there were 10 oppositions and 8 abstentions to the August 7, 2009 Consent Agenda, these oppositions and abstentions were attributed to Consent Agenda items other than the Rule Revision.

[33] 18 C.F.R. § 35.13 (2009).

waiver, the Filing Parties submit the additional information enumerated below in substantial compliance with relevant provisions of Section 35.13.

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

- This transmittal letter;
- Attachment 1: A Tariff sheet reflecting in blackline the change reflected in this filing;
- Attachment 2: A clean Tariff sheet incorporating the change reflected in this filing;
- Attachment 3: Prepared Testimony of Marc D. Montalvo, sponsored solely by the ISO;
- Attachment 4: Affidavit of Pallas Lee Van Schiack, PhD, sponsored solely by the ISO; and
- Attachment 5: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As noted in Section I of this transmittal letter, the Filing Parties request that the Rule Revision become effective on or after January 1, 2010, with two weeks' prior notice to be provided by the ISO for the actual effective date.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpnts_eserved.pdf. A paper copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners ("NECPUC"). The names and addresses of these governors and regulatory agencies are shown in Attachment 5. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified on Attachment 5 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

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

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

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

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

VII. CONCLUSION

For the foregoing reasons, the Filing Parties respectfully request that the Commission approve the Rule Revision to become effective on or after January 1, 2010 (subject to the provision of at least two-week notice by the ISO), without condition or change.

Respectfully submitted,

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Its Attorneys

Dated: October 23, 2009

cc: Governance Participants (electronically) and entities listed in Attachment 5

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ATTACHMENT 1

Blacklined Version of Tariff Sheet

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

(i) local TMOR RCPF = $25050/MWh;

ATTACHMENT 2

Clean Version of Tariff Sheet

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

(i) local TMOR RCPF = $250/MWh;

ATTACHMENT 3

Prepared Testimony of Marc D. Montalvo
Director, Market Development
ISO New England Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER10-___-000**
New England Power Pool	**)**	

TESTIMONY OF MARC D. MONTALVO

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A: My name is Marc D. Montalvo. I am the Director of Market Development with ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A: I have a Master of Science degree in Finance from Clark University and a Bachelor of Science degree in Mathematics from Allegheny College. My energy and utility industry experience includes power market design and implementation, risk management, resource planning and power project finance. I have sponsored direct testimony before the Commission in support of several of the ISO's market design proposals and have testified before state regulatory commissions and siting councils on issues including resource economics, portfolio design, and asset valuation. Prior to joining the ISO in 2004, I served as Manager of Wholesale Market Analytics at La Capra Associates, an energy industry consultancy. Before joining La Capra Associates, I was an Analyst in the generation operation and marketing group at New England Power Company.

Q: PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A: This testimony explains the reasons for proposing to increase the value of the Reserve Constraint Penalty Factor (sometimes referred to as "RCPF") for Thirty-Minute Operating Reserve ("TMOR") that applies to import-constrained Reserve Zones. The change would allow the real-time market system to economically dispatch resources to maintain the TMOR requirement in import-constrained Reserve Zones under a broader set of conditions, reducing the need for manual operator intervention. As a result, revising the RCPF would increase the efficiency of dispatch and pricing and reduce the congestion costs incurred to maintain local reserves.

Q: PROVIDE AN OVERVIEW OF THE REAL-TIME ENERGY AND RESERVE MARKETS.

A: In the real-time market, the ISO schedules resources to provide energy and reserves via a co-optimized market-clearing system. The co-optimization process produces real-time prices and scheduled quantities based on the submitted offer data and real-time operational constraints, including system and local reserve requirements and transmission constraints. When there is sufficient reserve supply (no reserve shortage or energy re-dispatch), reserve prices will be zero. When reserve constraints bind, the reserve clearing price will be positive, reflecting the opportunity cost of resources re-dispatched to provide reserves. Reserve clearing prices are capped at the value of the applicable RCPF for each type of reserve.

Q: WHAT ARE RESERVE CONSTRAINT PENALTY FACTORS?

A: For each reserve requirement (system or locational), there is an associated RCPF. In the real-time co-optimized energy and reserve market, the reserve clearing price reflects the re-dispatch costs that are incurred to maintain reserves. The RCPF serves as a cap on the reserve clearing price. The reserve clearing price is set at the RCPF if available reserves are not sufficient to satisfy the reserve requirement or if the cost of re-dispatch to procure reserves would otherwise exceed the RCPF.

Q: WHAT IS THE CURRENT VALUE OF THE RCPF FOR THIRTY-MINUTE OPERATING RESERVE?

A: For each of the three local reserve zones (including NEMA/Boston, Connecticut, and Southwest Connecticut), the RCPF for TMOR is $50/MWh.

Q: DESCRIBE THE MARKET RULE CHANGE.

A: The revised market rules would increase the RCPF for local TMOR to $250/MWh.

Q: WHAT IS THE PURPOSE OF INCREASING THE RCPF FOR THIRTY-MINUTE OPERATING RESERVE?

A: The choice of RCPF values determines how the co-optimized market-clearing system schedules resources and establishes prices during operating conditions when there is relative scarcity of reserves. When it is not possible to meet the reserve requirements, the RCPFs prevent the market-clearing system from incurring extraordinary costs for little or no reliability benefit. However, because the local RCPF is not sufficiently high, the market-clearing system does not schedule all available economic resources in the local area to meet the reliability requirements. If sufficient capacity is available to maintain reserves, a system operator intervenes to maintain reserves, manually scheduling generators or binding the second contingency proxy transmission constraint, resulting in a less efficient allocation of resources and distorting real-time market-clearing prices.

The initial decision to select a relatively low local TMOR RCPF of $50/MWh was based on the recognition that there is a heightened potential for economic or physical withholding in local areas. In 2006, when the co-optimized energy and reserve market design was put in service, there was relatively concentrated resource ownership in import-constrained areas and limited competition for the provision of reserve service, increasing the possibility that a market participant could strategically withhold reserves to increase real-time prices. The choice of the $50/MWh RCPF value attempted to balance the need to protect against market power abuse and the benefit of allowing the market-clearing system to re-dispatch resources.

A review of operating data since the introduction of the co-optimized real-time market suggests that the current RCPF value for local TMOR is not optimal. In both its 2007[1] and 2008[2] annual market assessments, the Independent Market Monitoring Unit ("IMMU") recommended that the local TMOR RCPF value be increased. The IMMU indicated that "actions taken by the ISO to maintain local reserves are often more costly than the RCPF, which indicates that the RCPF may be set inefficiently low."[3]

The ISO concurs with the IMMU's recommendation and the conclusion that an increased RCPF value would more effectively balance the objective of mitigating the exercise of market power and efficient dispatch of the electric network consistent with reliability requirements.

Q: DESCRIBE THE ANALYSIS CONDUCTED TO ASSESS THE APPROPRIATE LEVEL OF THE LOCAL TMOR RCPF.

A: The ISO conducted an analysis to determine the appropriate level of the local TMOR RCPF value. The data from this analysis show that with a local TMOR RCPF value of $50/MWh, the ISO must frequently intervene to schedule resources to meet the local TMOR requirement. The ideal RCPF value should allow the market system to optimize the use of resources within the constrained

[1] Independent Market Monitoring Unit for ISO New England Inc., 2007 Assessment of the Electricity Markets in New England (June 2008), available at: http://www.iso-ne.com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf (2007 Report).

[2] Independent Market Monitoring Unit for ISO New England Inc., 2008 Assessment of the Electricity Markets in New England (June 2009), available at: http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2008_immu_report_final.pdf (2008 Report).

[3] 2008 Report, Executive Summary, p. xiii.

area and transmission interface capability to most economically meet the local TMOR requirement.

The ISO has conducted more recent analysis to reevaluate the appropriate local TMOR RCPF value. A game theoretic analysis was performed to investigate the bidding behaviors of participants across a range of local TMOR RCPF values. Game theory is a technique used to analyze the strategic interactions among players in a competitive environment. As applied here, a dominant market participant in a local reserve zone determines its energy offer price and reserve capability so as to maximize profits subject to anticipated reactions by rival participants.

The analysis studied the impact of the choice of local TMOR RCPF on the bidding behaviors of the dominant participants who can exercise market power due to their relatively large capacity to provide energy/reserves. The interrelated energy and reserve markets in real time provide market participants with strategic opportunities in either market with price impacts occurring in both markets. These interactions constitute a non-cooperative multi-leader and one-follower Stackelberg game and the solution of the game is characterized by a generalized Nash Equilibrium. In particular, the dominant market participants play the role of the leader, deciding their offers. The follower is the joint energy and reserve market clearing mechanism employed by the ISO. The equilibrium outcome corresponds to the optimal strategies achieved by the players. The goal of the

Stackelberg game is to find a generalized Nash Equilibrium such that if any leader changes its actions unilaterally, its profit will decrease. Equilibrium exists when there is no incentive for any dominant participant to change its bidding behavior unilaterally.

A sequence of experiments was performed for the NEMA/Boston and SWCT local reserve zones under the game theoretic framework. The analysis examined the influence of the RCPF on participants' bidding behavior under different scenarios. In particular, the analysis evaluated dominant bidding strategies assuming various levels of the RCPF with and without the energy offer cap. It also examined the network environment with a relaxed interface limit, considering that investments in transmission improvements may be attracted as the RCPF rises. Moreover, because the economic benefit of using transmission interface capability to provide local reserves is a function of the relative price of power inside and outside the constrained area, the impact of relatively low hub prices on bidding behavior was evaluated.

The results of the analysis imply that although the RCPF will not eliminate the profit incentive for withholding reserve or marking up prices, it may reduce high prices associated with the exercise of market power. There always is some incentive for dominant generators to try to create artificial scarcity by withholding reserve from the markets or by charging energy higher than its actual cost under all of the circumstances. Given the limited role that the RCPF plays as a tool for market power mitigation, it is preferable to set the RCPF at a level such that the market system is able to schedule all available resources under the broadest set of conditions, improving market efficiency and limiting the need to take actions outside of the market process to maintain reliability. That is, the appropriate RCPF level should allow the local TMOR price to rise high enough to reflect scarcity and still mitigate market power to some extent.

Based on the main findings from the experiments and operation of the real-time market, it is recommended that the appropriate local TMOR RCPF level should be $250/MWh. This value approximates the difference between the cost of the typical local marginal units which are chosen to be dispatched under constrained operating conditions and the hub price. Given that the local reserve zone is usually a load pocket, the re-dispatch cost for procuring the local TMOR is approximately equal to the difference between the local energy price and the hub price most of the time. Thus, the suggested RCPF value provides a reasonable cap of the re-dispatch cost for maintaining TMOR in a local reserve zone when re-dispatch is necessary, and it also sends the appropriate price signal to the market participants. Moreover, since the proposed RCPF is determined by the marginal cost of the local generating units which set the price during shortage hours and the reserve price is capped by the RCPF, the market participants that control these marginal units would not gain any additional profit by raising their offer prices above true marginal costs. Hence, those participants have less, if any, incentive to mark up their prices during shortage events.

Q: HAVE YOU CONDUCTED AN ESTIMATED COST IMPACT OF INCREASING THE RCPF VALUE FOR THIRTY-MINUTE OPERATING RESERVE?

A: Yes. The ISO prepared a rough order of magnitude estimate of the net real-time local reserve costs and congestion costs in each local reserve zone in 2007 and 2008 had the $250/MWh RCPF value been in place. As noted earlier, in real time the dispatch and pricing of resources to meet the energy and reserve requirements are jointly optimized. Consequently, the cost directly associated with the maintenance of real-time local TMOR is approximated by the sum of the costs incurred as congestion when the second contingency proxy limit is bound by the operators and the cost of reserves as reflected in the reserve prices when the reserve constraints bind. The cost estimate considers two scenarios: (1) assuming the current $50/MWh RCPF value, and; (2) assuming the proposed $250/MWh RCPF value. The results provide a reasonable estimate of the probable magnitude and direction of the change in reserve costs if the $250/MWh local TMOR RCPF value is adopted.

The cost estimate analysis showed that in 2007 and 2008, reserve prices and costs would have been higher if the local TMOR RCPF value had been $250/MWh. However, the congestion costs resulting from activation of the second contingency proxy limit would have been significantly lower. The net result of the increase in the RCPF value actually is substantial savings because the reduction in congestions costs is larger than the increase in reserve costs. The results of the cost estimate are shown in the following tables.

RCPF	Cost to Maintain Real-Time Local TMOR, $Millions		
	NEMA/BSTN	CT	SWCT
$50/MWh	1.88	5.10	3.82
$250/MWh	1.10	2.46	1.54
Savings	0.78	2.64	2.28
Total Savings	5.70		
% Cost Reduction	53%		

Table 1: Savings resulting from RCPF = $250/MWh in 2007

RCPF	Cost to Maintain Real-Time Local TMOR, $Millions		
	NEMA/BSTN	CT	SWCT
$50/MWh	4.45	1.40	0.33
$250/MWh	1.42	0.27	0.31
Savings	3.03	1.13	0.02
Total Savings	4.18		
% Cost Reduction	68%		

Table 2: Savings resulting from RCPF = $250/MWh in 2008

The cost to maintain real-time local TMOR reported in Table 1 and Table 2 is approximated by the sum of the costs incurred as congestion when the second contingency proxy limit is bound by the operators and reserve prices. Because congestion costs dominate the overall costs to maintain real-time local TMOR, the results of the cost estimate indicated that the total congestion cost associated with binding the transmission proxy limit to maintain local reserves would have been about 53% lower in 2007 and 68% lower in 2008 had the local TMOR RCPF been $250/MWh.

Q: SHOULD THE COMMISSION DETERMINE THAT THE INCREASE IN THE RCPF VALUE IS JUST AND REASONABLE?

A: Yes. The proposed $250/MWh RCPF value approximates the difference between the cost of the typical local marginal units which are chosen to be dispatched under constrained operating conditions and the hub price. The $250/MWh local

TMOR RCPF value reflects a more realistic re-dispatch cost for procuring the local TMOR when reserves are scarce as a result of either market power or normal operation of markets. The $250/MWh value also sends the appropriate price signal to the market participants, and provides sufficient incentive for investment. At this RCPF level, the system can economically dispatch resources to maintain the TMOR requirement at the local area without frequent market interventions by the control operators.

On balance, increasing the local TMOR RCPF from $50/MWh to $250/MWh produces overall market efficiency gains, reducing the net cost of maintaining reliability in constrained areas. The proposed RCPF more accurately reflects the cost of maintaining local reserves in the real-time market, improving incentives for market-based day-ahead commitments in the local areas. In general, more day-ahead commitments reduce the need for supplemental commitments during the Resource Adequacy Assessment process and shift local reliability costs from Net Commitment Period Compensation payments to market-clearing prices. Higher RCPFs better reflect the cost of maintaining reserves, potentially improving price signals for capital investment in constrained areas.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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

Executed on October 22, 2009.

Marc D. Montalvo

ATTACHMENT 4

Affidavit of Pallas Lee Van Schiack, PH.D.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER10-___-000**
New England Power Pool	**)**	

AFFIDAVIT OF PALLAS LEE VAN SCHAICK, PH.D.

I. Background and Qualifications

1. My name is Pallas Lee Van Schaick. I am an economist and a vice president at Potomac Economics. Our office is located at 9990 Fairfax Boulevard, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets.

2. I currently lead much of the work of Potomac Economics in its roles as the Independent Market Advisor for the New York Independent System Operator, Inc. ("NYISO") and as the Independent Market Monitoring Unit ("IMMU") for ISO New England Inc. ("ISO-NE" or "ISO"). Among other duties as the IMMU for the ISO-NE, I co-authored the 2007 and 2008 Assessments of the Electricity Markets in New England referenced in Mr. Montalvo's testimony.[1]

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[1] Montalvo Testimony at p. 5.

3. I have worked as an energy economist for nine years, focusing primarily on wholesale power markets in New York, New England, and Texas. I have provided strategic advice and analysis in the areas of wholesale market design and market power issues.

4. Before joining Potomac Economics, I worked as an associate for Charles River Associates. I hold a Ph.D. and M.A. in Economics from George Mason University and a B.A. in Economics and Physics from the University of Virginia.

II. Purpose of Affidavit

5. In the filing with which this affidavit is submitted, ISO-NE proposes to increase the Reserve Constraint Penalty Factors ("RCPFs") for local reserve zones from $50/MWh to $250/MWh. The proposed change would improve the efficiency of the real-time energy and reserve markets when the ISO must re-dispatch resources in order to maintain sufficient levels of reserves in local areas. The purpose of this affidavit is to explain that the proposed change in the local RCPFs will not generally enhance local market power in New England, and to discuss how ISO-NE's existing market power mitigation measures would address potential market power in local reserve zones.

6. Section III describes how local reserve zone constraint modeling enhances market efficiency by lowering the cost of satisfying local reserve requirements. Section IV explains why the proposed change in the local RCPFs is necessary for local reserve zone constraint modeling to function effectively. Section V illustrates

why the New England market would not generally be more susceptible to the exercise of market power under the proposed RCPFs. Section VI discusses the existing mitigation measures which adequately address the potential exercise of market power.

III. Local Reserve Zone Constraint Modeling

7. In local reserve zones, ISO-NE is required to schedule sufficient resources to maintain service in case the two largest local contingencies occur within a 30-minute period. To satisfy this requirement, the ISO can schedule: (i) internal 30-minute reserves, which are available reserves that can be ramped within 30 minutes; or (ii) imported reserves, which are held on the transmission interface into the local reserve zone when internal generators produce additional energy in order to unload the transmission interface.

8. Although it is possible to satisfy local reserve requirements using non-market mechanisms such as OOM ("out-of-merit") dispatch instructions, the ISO uses two market-based mechanisms in the real-time market: (i) local reserve zone constraint modeling, the enhanced approach introduced in October 2006; and (ii) Proxy Second Contingency ("PSC") constraint modeling, the older approach used since the introduction of the multi-settlement, locational marginal pricing system. Local reserve zone constraints enable the real-time market model to calculate the optimal (*i.e.*, lowest-cost) breakdown of imported reserves and internal 30-minute reserves. PSC constraints require the real-time market model to satisfy the

reserve requirement with imported reserves only. Therefore, in order to place reserves on internal generators, the operator must manually determine the amount of reserves that can be held internally, and then adjust the PSC constraint accordingly.[2]

9. Local reserve zone constraint modeling is more efficient than PSC constraint modeling because local reserve zone constraints allow the real-time market model greater flexibility to determine the optimal allocation of reserves. When local reserve zone constraints are used, the real-time market model can reduce energy imports to allow more imported reserves or it can back down internal generators to allow them to provide reserves, whichever results in a lower overall cost. Since the quantity of internal reserves must be determined manually, PSC constraint modeling can lead the real-time market model to import reserves when it would be less costly to schedule internal 30-minute reserves. Furthermore, PSC constraint modeling may lead the real-time market model to hold more internal 30-minute reserves than necessary to satisfy the reserve requirement.

10. Both modeling approaches can be used in the real-time market, and therefore, produce Locational Marginal Prices ("LMPs") that reflect the marginal cost of dispatching generation to satisfy the local reserve requirements. Local reserve

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[2] For example, if the operator determines that 100 MW of non-spinning reserves is available on internal off-line fast-start generators, the operator will raise the PSC constraint 100 MW, which reduces the amount of imported reserves and increases the amount of imported energy.

zone constraint modeling also produces reserve clearing prices that reflect the marginal cost of satisfying the reserve requirement. In contrast, PSC constraint modeling does not produce reserve clearing prices because the costs of satisfying the reserve requirements are not explicitly recognized in the real-time market model.

IV. Effects of the Proposed Local RCPF

11. The RCPF puts an upper limit on the cost that the real-time market model can incur to satisfy a local reserve zone constraint. Consequently, if the cost of maintaining the required level of reserves exceeds the RCPF, the real-time market model will incur a reserve shortage and set the reserve clearing price based on the level of the RCPF. The RCPF prevents the model from incurring extraordinary costs for little or no reliability benefit when it is not possible to satisfy the reserve requirement. However, if the RCPF is not sufficiently high, the model may not schedule all available resources to meet the reserve requirement. To prevent reserve shortages in such instances, the operator models a PSC constraint so that the real-time market model will schedule all available resources to satisfy the reserve requirement. Since PSC constraint modeling is less efficient than local reserve zone constraint modeling, it is important to set the RCPF high enough to maintain adequate local reserves.

12. The ISO's proposal to raise the RCPF to $250/MWh would improve the efficiency of the local reserve zone constraint modeling because the RCPF would

be high enough to satisfy the local reserve requirements in the vast majority of cases. In 2008, the marginal cost of meeting the local reserve requirement exceeded the current RCPF of $50/MWh in approximately 64 percent of the real-time market intervals when re-dispatch was necessary to satisfy the reserve requirement in a local reserve zone. In contrast, the marginal cost of meeting the local reserve requirements exceeded the proposed RCPF of $250/MWh in just 6 percent of intervals.

13. The ISO's proposal to raise the RCPF will reduce the cost necessary to maintain adequate local reserves in some cases. For example, the marginal re-dispatch cost exceeded the proposed RCPF of $250/MWh on just two days in 2008. In these intervals, the local reserve requirement was satisfied using a PSC constraint, which led the real-time market model to import more reserves than would have been optimal. As a result, less off-line fast-start capacity was scheduled to provide reserves, leading to higher marginal re-dispatch costs than if the RCPF had been $250/MWh. Hence, if the RCPF had been $250/MWh on these two days, the marginal re-dispatch costs would likely have been lower than $250/MWh.

V. Effects of the RCPF on Market Power

14. The unique characteristics of electricity markets create significant potential for market power in local import-constrained areas. Accordingly, any attempt to exercise market power in local import-constrained areas is limited by the ISO's

market power mitigation measures, which are explained further in Section VI. This section explains why, absent the mitigation measures, the proposal to raise the local RCPF to $250/MWh would not generally enhance market power in local areas.

15. As explained in the previous section, local reserve zone constraint modeling and PSC constraint modeling are both market-based mechanisms that are used to satisfy local reserve requirements. Clearing prices tend to rise when the supply of generating capacity and/or reserve capacity is reduced. Hence, it is important to assess whether suppliers have incentives to artificially reduce supply in order to raise clearing prices above competitive levels. This section discusses the strategies that might be used to exercise market power and shows that the resulting LMP-effects under local reserve zone constraint modeling would be the same as or smaller than under PSC constraint modeling.

16. Suppliers may attempt to exercise market power by withholding supply from the market. Economic withholding includes strategies such as attempting to raise energy and reserves clearing prices by increasing incremental energy offers above competitive levels and by reducing manual ramp rate offers below the capability of the generator. Physical withholding includes strategies such as attempting to raise clearing prices by inappropriately de-rating generating capacity and by falsely declaring that fast-start capacity cannot start within 30 minutes of a contingency. Such withholding strategies are designed to reduce the supply of

generating capacity, reserve capacity, or both in order to raise clearing prices above the competitive level.

17. The following example illustrates why withholding would generally not be more effective under local reserve zone constraint modeling and, in some cases, would be more effective under PSC constraint modeling. Suppose that a local area is served by $60 imported energy, off-line non-spinning reserves, and an internal generator at its low operating limit with 50 MW of available $80 capacity and 50 MW of available $100 capacity. In this case, the LMP would be set at $60 by the imported energy. Further suppose that 100 MW of off-line non-spinning reserves are withheld, requiring the ISO to find 100 MW of reserves from other resources.

18. Under local reserve zone constraint modeling, suppose the model determines the optimal way to satisfy the need for reserves is to dispatch 50 MW from the $80 range of the internal generator, allowing it to provide 50 MW of spinning reserves from the high-cost range. The increased output from the internal generator leads to a 50 MW reduction in imported energy, which increases imported reserves by 50 MW, satisfying the reserve requirement. In this case, the LMP would be set at $80 by the internal generator.

19. Under PSC constraint modeling, the LMP-effect of withholding would be the same as under local reserve zone constraint modeling if the operator determined the optimal manual settings. If the operator assumes the internal generator will provide 50 MW of spinning reserves, the operator would reduce the energy

import limit by 50 MW in order to import 50 MW of reserves. This would lead to the dispatch of 50 MW from the $80 generator. In this case, the LMP would be set at $80, so the effect on LMPs would be the same as under local reserve zone constraint modeling.

20. However, the LMP-effect of withholding could actually be greater under PSC constraint modeling if the operator did not choose the optimal manual settings. For example, if the operator did not recognize that the internal generator could provide 50 MW of spinning reserves when its high-cost capacity is not dispatched, the operator would reduce the energy import limit by 100 MW. In this case, the LMP would be set at $100, so the effect on LMPs would be greater than under local reserve zone constraint modeling.

21. I would note that the effect on reserve clearing prices would be greater under local reserve zone constraint modeling, since PSC constraint modeling does not directly influence reserve clearing prices. In the example, the reserve clearing price is initially $0, and it increases to $20 after reserves are withheld under local reserve zone constraint modeling. In contrast, the reserve clearing price would remain at $0 after reserves are withheld under PSC constraint modeling. Therefore, the LMP-effects of withholding under local reserve zone constraint modeling are generally the same as or lower than under PSC constraint modeling, while the effects on reserve clearing prices are greater under local reserve zone constraint modeling, since PSC constraint modeling does not directly influence reserve clearing prices. However, this concern is diminished due to the forward reserve

market because the majority of local reserves are provided by generators with forward reserve obligations. These suppliers are paid according to the reserve clearing price in the forward reserve auction rather than the real-time market, so they have less incentive to raise the real-time reserve prices.

VI. Mitigation Measures Address Potential Exercise of Market Power

22. To safeguard against the potential exercise of market power, ISO-NE currently has market power mitigation measures in place that are effective in limiting the exercise of market power in areas that are constrained due to local reserve requirements. The mitigation measures have provisions to address economic and physical withholding, and these measures apply similarly whether local reserve zone constraints or PSC constraints are modeled. In either case, the mitigation measures apply if withholding would lead to a substantial increase in LMPs. Hence, I expect the existing mitigation measures will continue to address the potential exercise of market power if the RCPF is increased to $250/MWh as proposed.

23. The mitigation measures identify conduct that may be considered economic withholding in import-constrained areas. This includes conduct such as raising the incremental energy offer above the reference level by the lower of $25/MWh or 50 percent or reducing the manual ramp rate offer by more than 50 percent. If such conduct has an estimated impact of increasing LMPs or reserve clearing

prices by the lower of $25/MWh or 50 percent, the offers are mitigated, meaning that the offers are replaced by the reference levels.

24. The mitigation measures also identify conduct that may be considered physical withholding in import-constrained areas. This includes conduct such as inappropriately de-rating generating capacity below its physical capability and falsely declaring that a fast-start generator is not capable of starting quickly enough to provide non-spinning reserves. If the market monitor observes such conduct and it has an estimated impact of increasing LMPs or reserve clearing prices by the lower of $25/MWh or 50 percent, the market monitor can refer the conduct to the Federal Energy Regulatory Commission for potential monetary sanctions.

25. Since LMP was introduced in March 2003, these mitigation measures have been effective in addressing the potential attempts to raise clearing prices above competitive levels in areas with local reserve requirements. Given that the likely impact of withholding is likely to be similar whether local reserve zone constraints are modeled or PSC constraints are modeled, it is reasonable to expect the mitigation measures will be adequate if the RCPF is increased as proposed.

26. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing Affidavit of Pallas Lee Van Schaick, Ph.D. dated October 19, 2009 (the "Affidavit"). I have read the Affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Pallas Lee Van Schaick

October 19, 2009

Subscribed and sworn to before me

this 19th day of October, 2009

MATTHEW JAMES CARRIER
Notary Public
City/County of Fairfax
Commonwealth of Virginia
Notary registration number - 7233763
My commission expires - Nov. 30, 2013

Notary Public

My commission expires: 11/30/2013

ATTACHMENT 5

List of New England Governors and Utility Regulatory Agencies

The Honorable M. Jodi Rell
State Capitol
210 Capitol Ave.
Hartford, CT 06106

Connecticut Dept. of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018

The Honorable John E. Baldacci
One State House Station
Rm. 236
Augusta, ME 04333-0001

The Honorable Deval Patrick
Office of the Governor
Rm. 360 State House
Boston, MA 02133

Massachusetts Dept. of Public Utilities
One South Station
Boston, MA 02110

The Honorable John H. Lynch
State House
25 Capitol Street
Concord, NH 03301

New Hampshire Public Utilities Commission
21 South Fruit Street
Ste. 10
Concord, NH 03301-2429

The Honorable Donald L. Carcieri
State House Room 115
Providence, RI 02903

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

The Honorable James H. Douglas
109 State Street, Pavilion
Montpelier, VT 05609

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

Harvey L. Reiter, Esq.
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Of Public Utilities Commissioners, Inc.
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Washington, DC 20036-3816

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

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